Decision **PROPOSED DECISION OF ALJ POWELL (Mailed on 7/16/2019)**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2019-2021. (U39G.) | Application 17-11-009 |

# DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S 2019-2022 REVENUE REQUIREMENT FOR GAS TRANSMISSION AND STORAGE SERVICE

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# DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S 2019-2022 REVENUE REQUIREMENT FOR GAS TRANSMISSION AND STORAGE SERVICE

## Summary

This decision adopts $1.327 billion for Pacific Gas and Electric Company's (PG&E) 2019 revenue requirement to provide gas transmission and storage services. The adopted revenue requirement is a 2 percent increase over the amount currently in effect, $1.3 billion, and an 11 percent decrease from the revenue requirement that PG&E requested, $1.48 billion. The difference in the revenue requirements reflects the forecast adjustments discussed throughout this decision. This decision also adopts a rate design and cost allocation methodology for PG&E's storage services and local and backbone transmission services.

As requested by PG&E, this decision adopts a third attrition year (2022). Appendix E contains the summary of adopted results of operations and the base revenue requirement for the post-test year ratemaking for 2020 through 2022. This decision also adopts PG&E's Natural Gas Storage Strategy, subject to a Tier 2 Advice Letter concerning the decommissioning of PG&E's Los Medanos storage field, among other requirements.

This proceeding is closed.

## 1. Background

On November 17, 2017, Pacific Gas and Electric Company (PG&E) filed an application requesting that the Commission adopt its gas transmission and storage (GT&S) revenue requirement, cost allocation, and rate design for the period of 2019-2022.[1] A prehearing conference (PHC) was held on January 4,

[1] The 2019-2022 period is referred to in this decision as the "rate case period."

2018. The assigned Commissioner and Administrative Law Judge (ALJ) issued a Scoping Memo and Ruling on April 24, 2018. Public Participation Hearings were held on July 11, 17, 24, and 30 of 2018. An evidentiary hearing was held intermittently from September 27 to October 19, 2018. Subsequently, PG&E and The Utility Reform Network (TURN) filed motions for transcript corrections.

The following parties filed opening briefs: ABAG Power (ABAG), Dynegy Moss Landing, LLC (Dynegy); California Manufacturers & Technology Association (CMTA); California State University (CSU); California Public Advocates Office (Cal Advocates); Calpine Corporation (Calpine); Coalition of California Utility Employees (CCUE); Commercial Energy of California (Commercial Energy); Gas Transmission Northwest LLC (GTN); Gill Ranch, LLC, (Gill Ranch); Indicated Shippers;[2] Northern California Generation Coalition (NCGC); Office of the Safety Advocate (OSA); PG&E; Sacramento Municipal Utility District (SMUD); Southern California Generation Coalition and City of Palo Alto (SCGC); TURN; Central Valley Gas Storage, LLC, Lodi Gas Storage, LLC, Wild Goose Storage, LLC (together, Joint ISPs); Tiger Natural Gas, Inc., United Energy Trading, LLC, Just Energy Solutions, School Project for Utility Rate Reduction, and Vista Energy Marketing (together, Core Transport Agent Parties or CTA Parties).

On December 14, 2018, Indicated Shippers filed a motion to strike portions of PG&E's opening brief, and Calpine, NCGC, and PG&E filed timely responses. On the same day, reply briefs were filed by Dynegy, CCUE, Calpine, Commercial

[2] The members of Indicated Shippers are Aera Energy LLC, Chevron U.S.A. Inc., Phillips 66, Shell Oil Products US, and Tesoro Refining & Marketing Company LLC.

Energy, CMTA, CTA Parties, GTN, Gill Ranch, Indicated Shippers, NCGC, OSA, PG&E, Cal Advocates, SCGC, SMUD, TURN, and Joint ISPs.

On April 25, 2019, the Commission issued Decision (D.) 19-04-044 to extend the statutory deadline in this proceeding from May 19, 2019, to November 19, 2019.

Another PHC was held on February 13, 2019, to establish a schedule for processing supplemental testimony that PG&E filed concerning its compliance with Senate Bill (SB) 901.

## 2. Legal and Ratemaking Principles

### 2.1. Burden of Proof

All rates and charges collected by a public utility must be "just and reasonable,"[3] and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified."[4] Thus, the Commission requires that the public utility demonstrate with admissible evidence that the costs which it seeks to include in revenue requirement are reasonable and prudent.

The standard of proof the PG&E must meet is that of a preponderance of evidence. Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[5] In short, PG&E must present more evidence that supports the requested result than would support an alternative outcome.

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[3] Public Utilities Code Section 451. Subsequent statutory references, unless otherwise noted, are to the California Public Utilities Code.

[4] Section 454.

[5] D.08-12-058 at 19 (citing Witkin, Calif. Evidence, 4th Edition, Vol. 1 at 184).

A disallowance is warranted even when the forecasted work is necessary if: (1) the utility had not originally performed the work properly; (2) the utility had failed to comply with regulatory requirements that it was previously funded to perform; or (3) the costs to be incurred are due to clear and identifiable failures and errors.

In addition, a disallowance could be directed for the 2019-2022 forecasted work if that work was also authorized in the prior rate case proceeding and, therefore, included in rates even though PG&E did not perform the authorized work during the prior rate case cycle (deferred work). Pursuant to the settlement agreement adopted in the 2014 GT&S proceeding, the parties agree to resolve disputes concerning deferred work using six principles and three conditions. The principles are:

1. Where funds are originally collected from ratepayers based on representations that the work is necessary to provide safe and reliable service and, yet, PG&E does not perform all of the designated work, the fact that PG&E must pay for a higher priority activity or program does not nullify or extinguish its responsibilities to fund forecasted and authorized work unless such work is no longer deemed necessary for safe and reliable service.
2. PG&E is responsible for providing safe and reliable customer service whether or not its overall spending matches funding levels authorized or imputed in rates.
3. PG&E bears the risk that, as a result of meeting spending obligations necessary to provide safe and reliable service, the earned rate of return may be less than the authorized return.
4. While PG&E has finite funds to meet capital and operational needs, PG&E is not restricted to spending only up to the forecast adopted in a General Rate Case (GRC).
5. PG&E bears the responsibility – and has discretion – to adjust priorities to accommodate changing conditions after test year

forecasts are adopted. Readjusting spending priorities, however, only involves the ranking and sequence of spending. Reprioritizing spending for new projects does not automatically justify postponing projects previously deemed necessary for safe and reliable service.

6. The GRC process is a tool in supporting PG&E's ongoing ability to provide safe and reliable service while affording a reasonable opportunity to earn its rate of return and thereby attract capital to fund its infrastructure needs. Adopted revenue requirements and the disposition of disputed ratemaking issues should be consistent with the goal of supporting PG&E's ability to provide safe and reliable service while maintaining its financial health and ability to raise capital.[6]

In addition, if the following conditions are true, PG&E will need to take additional steps in order to seek ratepayer funding for deferred work. The conditions are:

a. The work was requested and authorized based on representations that it was needed to provide safe and reliable service;
b. PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and
c. PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.[7]

For forecasted work that meets these conditions, PG&E's direct showing in support of the reasonableness of its forecast must also explain "(i) why the authorized work was not performed in the time forecasted, (ii) how the authorized funding was used, if at all, for other purposes and (iii) whether such other purposes related to the provision of safe and reliable service."[8] If the

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[6] D.17-05-013 at 187-188.

[7] *Id. at* 188-189.

[8] D.14-08-032 at 197.

authorized funding for safety-related work was used for other purposes, PG&E's showing must also demonstrate the alternative work was just and reasonable.

We have analyzed the record in this proceeding within these parameters.

### 2.2. Issues Before the Commission

Pursuant to the Scoping Memo, issued on April 24, 2018, the issues to be resolved in this proceeding are whether:

1. The proposed revenue requirements for natural GT&S services for 2019 are just and reasonable and adequate for PG&E to safely and reliably operate and maintain its natural GT&S assets.
2. PG&E's proposed post-test year attrition adjustments for 2020 and 2021 are just and reasonable, and the Commission should authorize PG&E to implement the annual adjustments each year.
3. The proposed rates for GT&S services for 2019, 2020, and 2021 are just and reasonable.
4. If the Commission adopts a third post-test year, then the proposed revenue requirement and rates for 2022 are just and reasonable.
5. PG&E's risk management process provides a reasonable framework for evaluating the reasonableness of PG&E's forecast revenue requirements.
6. The proposed two-way balancing account for Transmission Integrity Management expense costs should be adopted.
7. The Commission should adopt the proposed New Gas Statutes, Regulations, and Rules Memorandum Account to allow PG&E to track capital expenditures and expenses that are not forecast in this case, but are necessary to comply with anticipated new regulations.
8. The one-way balancing account for Work Required by Others (WRO) should be discontinued.
9. The proposed two-way Gas Storage Balancing Account should be adopted.
10. PG&E's Natural Gas Storage Strategy should be approved by the Commission, including but not limited to the following elements:

(a) conversion of Los Medanos and Pleasant Creek to production facilities in November 2019; (b) allocation of decommissioning and depreciation costs to core and noncore customers through end-use rates; (c) allocation of storage capacity in the amounts proposed by PG&E; and (d) the reasonableness of the Gill Ranch Storage costs to be included in rates.

11. The Memorandum of Understanding (MOU) attached to Chapter 11 should be adopted.
12. The one-way balancing account for Engineering Critical Assessment Phase 1 and Phase 2 should be discontinued.
13. The costs to replace electrically contacted cased crossings in the rate case period are recoverable from ratepayers and not subject to a 19 percent disallowance.
14. The Commission should conduct a reasonableness review of the costs for Line 407 in a Phase 2 of this proceeding, based upon a submission by PG&E in the first quarter of 2018 that includes recorded cost data. If any small amounts remain unrecorded at the time Phase 2 begins, the Commission should include the remaining forecast costs into the reasonableness review.
15. PG&E's cost allocation and rate design proposals are just and reasonable.
16. Allocating local transmission costs based on an average of cold year and average year forecast, winter season demands, is reasonable.
17. PG&E's proposed $0.04 differential between Redwood and Baja path rates is reasonable and should be adopted.
18. The GT&S Revenue Sharing Mechanism (GTSRSM) should be modified to: (1) allocate 100 percent of noncore local transmission over- and under-collections to customers; (2) change the sharing of noncore backbone and core backbone usage over- and under-collections to 75 percent to customers and 25 percent to shareholders; (3) remove noncore storage from the GTSRSM; (4) eliminate the $30 million "seed value;" and (5) change the timing of the annual transfer of the balance in the GTSRSM to December 31.

19. PG&E's proposal to adjust for the difference between the costs filed in this Application and the costs ultimately adopted in certain separate proceedings should be adopted.
20. The forecast of plant and rate base should be approved.
21. The forecast of depreciation reserve and expense and accompanying depreciation parameters and rates should be approved.
22. PG&E's throughput and demand forecasts described in Chapter 16C are reasonable and should be adopted.
23. Core Gas Supply's proposal to alter its inventory and withdrawal capacity adjustments, request for firm gas storage from Independent Storage Providers, Redwood Path and Baja Path transmission capacity adjustments, a core gas supplier firm storage holding verification requirement, and conforming changes to the Interstate Capacity Planning Range, the Incremental Core Gas Storage Decision, and the Core Procurement Incentive Mechanism (CPIM), are reasonable and should be adopted.
24. PG&E complied with Section 3.2.8.4 of PG&E's 2017 GRC Settlement.
25. The Z-Factor Memorandum Account should continue.
26. The Tax Act Memorandum Account should continue.
27. The following memorandum accounts should be closed: Hydrostatic Pipeline Testing Memorandum Account, Transmission Integrity Management Program (TIMP) Memorandum Account, Hydrostatic Station Testing Memorandum Account, Critical Documents Program Memorandum Account, Tax Normalization Memorandum Account, Gas Transmission and Storage Memorandum Account, and the Line 407 Memorandum Account.[9]

[9] Scoping Memo, Appendix A.

This decision resolves the aforementioned issues. The forecasts adopted herein will be adjusted in accordance with the Post-Test Year Ratemaking stipulation discussed in section 12 of this decision.

## 3. Other General Issues

### 3.1. Service Disconnections

Pursuant to Section 718, PG&E provided testimony concerning the rate of service disconnections in its territory and related internal policies and practices. In addition, PG&E performed an analysis to determine whether there is a direct correlation between the rate of service disconnections and utility bill increases.

Based on its analysis, PG&E determined that, if its proposed rate increase is adopted, the energy utility bills for customers who qualify for the California Alternate Rates for Energy (CARE) program would increase by $0.66 per month. PG&E also identified a direct correlation between bill increases and the amount of service disconnections for CARE customers; however, PG&E argues that it does not expect significant disconnections given the size of the increase.[10]

In addition, PG&E determined that there is no correlation between bill increases and disconnection rates for non-CARE customers.[11] PG&E notes that, based on the Commission's report on disconnection issues and trends,[12] other factors cause service disconnections for non-payment. These factors include public utility and Commission policies, unemployment rate, and regional location within the state.

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[10] When the monthly bills for CARE customer increased by $12, disconnections increased by 216 customers. PG&E Opening Brief at 3-1.

[11] PG&E Opening Brief at 3-1; Exhibit (Exh.) PG&E-30 at 7, Tables 1 and 2.

[12] Exh. PG&E-30 (citing A Review of Residential Customer Disconnection Influences & Trends, December 28, 2017).

TURN recommends that PG&E cap its service disconnection rate at 2017 levels for the instant rate case period. TURN argues that its recommendation is consistent with the objective of SB 598, which requires the Commission to develop policies, rules or regulation that help reduce the instances of service disconnections for nonpayment by residential customers.[13] PG&E disagrees with TURN's recommendation and argues that the Commission's proceeding in Rulemaking (R.) 18-07-005, which is a rulemaking concerning disconnection rates, is the appropriate forum for TURN's request.

We find that PG&E's testimony is consistent with Section 718. We agree that the affordability of rates should be considered when a utility requests a rate increase, as is the case here. PG&E's analysis demonstrates that its proposed rate increase will have no effect on non-CARE customers. While PG&E anticipates a negligible impact to the disconnection rate for CARE customers, that impact is further diminished, and likely eliminated, by the various adjustments to PG&E's proposed revenue requirement adopted in this decision. We decline to require PG&E to cap residential service disconnection levels here, as service disconnection policies are being considered in R.18-07-005.

### 3.2. Reporting Requirements

PG&E proposes to consolidate into one annual report (GT&S Annual Report) the information filed in its GT&S Report and its quarterly Transmission Pipeline Compliance Report. The prototype for the new GT&S Annual Report was developed through a workshop, hosted by the Commission's Energy Division and Safety Enforcement Division (SED) on July 9, 2018. Subsequently, PG&E and Cal Advocates revised the report prototype to incorporate

[13] TURN Opening Brief at 30-32.

stakeholder comments. On July 25, 2018, PG&E submitted the report prototype to the service list of the instant proceeding.[14]

PG&E and Cal Advocates propose a joint stipulation requesting that (1) the Commission adopt the new GT&S Annual Report format, (2) the Commission conduct a biennial workshop to determine if further updates are necessary, and (3) PG&E file a Tier 2 Advice Letter to implement updates requested from the workshops. In addition, Cal Advocates and PG&E agree to reevaluate whether information concerning project status details should be included in the GT&S Annual Report.[15]

We find that the stipulation is reasonable, subject to conditions. We find that additional information is necessary to produce a comprehensive report. Accordingly, we require PG&E to include the following information in its GT&S Annual Report: 1) pin citations to information related to or required by Section 591 related to its gas transmission and storage system,[16] 2) an explanation of how imputed and budgeted amounts were derived and their relationship to Commission authorized amounts,[17] 3) a listing of long-term goals PG&E has established for various programs beyond the rate case period, and PG&E's progress toward meeting such goals,[18] and 4) a report on the status of PG&E's

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[14] Exh. JS-01 at 1.

[15] *Id.*

[16]Section 591 requires electrical and gas corporations to annually notify the Commission of instances where the utility redirected funds authorized by the Commission for maintenance, safety, or reliability. D.19-04-020 requires a public utility to include § 591 compliance information in the utility's RSARs. *See* D.19-04-020 at 37.

[17] For example, Exh. JS-01 GT&S report prototype Table 3-3.

[18] For example, In-Line Inspection Upgrades Exh. PG&E -1 at 2-5.

Emergency Response Programs, including the installation of automated valves and other forecasted work.

We also find that reducing the frequency of the Transmission Pipeline Report from a quarterly to an annually basis would not provide the Commission with timely information of PG&E's pipeline transmission operations. Currently, PG&E is submitting the GT&S Report on a semi-annual basis. Accordingly, we direct PG&E to file a Tier 2 Advice Letter with a proposal for providing the information in the new report format on a semi-annual basis.

With the revisions noted above, the joint stipulation in Exhibit JS-01 is adopted.

### 3.3. Combination of GT&S Rate Case with PG&E's GRC

The Commission instituted R.13-11-006 to consider, among other issues, whether PG&E's GT&S and GRC proceedings should be consolidated. PG&E asserts that the Commission should combine the proceedings beginning with the 2023 GRC. Several parties opine on this issue as well. We find that, because this topic is the primary issue that the Commission seeks to address in R.13-11-006 and, unlike this proceeding, the rulemaking proceeding contains evidence concerning PG&E's GRC proceeding, a determination on this issue should be deferred to the rulemaking proceeding, R.13-11-006.

### 3.4. Four-Year Rate Case Cycle

In its instant application, PG&E includes a forecast for a third attrition year (2022) so that if, pursuant to R.13-11-006, the Commission decides to consolidate PG&E's GT&S and GRC proceeding, PG&E will be able to combine the proceedings starting in 2023, the test year for the next GRC filing.[19]

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[19] Exh. PG&E-1 at 2-11.

We find that PG&E's request to adopt a forecast for an additional attrition year is reasonable. As PG&E states, adopting the third attrition year is necessary to consolidate its GT&S and GRC proceedings; thus, declining to adopt the 2022 attrition year could adversely interfere with another Commission proceeding. We also find that adopting the additional attrition year would provide PG&E with more time to implement the Natural Gas Storage Strategy (NGSS)-related filing and reporting requirements that the Commission directs for PG&E in this decision, as discussed in section 5.

Moreover, we find that adopting the 2022 attrition year is necessary to allow PG&E to transition from its current GT&S risk management process to the Risk Assessment Mitigation Phase (RAMP) and Safety Model Assessment Proceeding (S-MAP) processes, as discussed in section 4. PG&E's RAMP process identifies GT&S risk and the associated expense and capital forecasts for projects and activities needed to mitigate or remove the identified risks; however, this information is not used in PG&E's GT&S proceeding because, under the current rate case schedule, the results of the RAMP process are not available before PG&E submits its GT&S application for the upcoming rate case cycle.

Specifically, pursuant to the current rate case plan, the RAMP process begins on September 1 of the year prior to the GRC filing date. Results of the RAMP must be incorporated into the GRC filing during the months of May through August prior to the GRC filing date. Because PG&E's next GRC will be filed in Fall 2021 for Test Year 2023, its RAMP and S-MAP processes will occur in 2020.[20] Thus, if the Commission declines to adopt the attrition year, PG&E's next GT&S rate case will be filed in 2020, preventing it from effectively using the

[20] D.14-12-025 at 41-42.

RAMP process to assess and forecast mitigation activities with the most current data for its gas transmission and storage risks.

## 4. PG&E's Risk Management Approach

PG&E's risk management approach is based on the methodology that the Commission found reasonable in PG&E's 2015 GT&S proceeding. PG&E uses an Integrated Planning Process (IPP) to implement its company-wide strategic asset planning initiatives. As part of the IPP, PG&E uses various committees to conducts risk management activities such as identification, assessment, planning and compliance. To identify risks within its gas operations, PG&E first identifies relevant threats for each asset family and non-asset family using the threat categories of threats provided in American Society of Mechanical Engineers (ASME) B31.8S standard. PG&E analyzes the threats using a matrix that includes the status of controls and mitigations available to thwart or resolve each threat.

Using the threat matrix, PG&E identifies the risks that each threat poses to each asset family, across asset families, and to non-asset family programs, such as Operations and Maintenance. The identified risks are entered into PG&E's Risk Evaluation Tool (RET), which calculates a risk score for each risk. PG&E has revised its method for calculating RET scores to make the process consistent with its company-wide scoring criteria. PG&E's subject matter experts (SME) refine the score as needed and document the revision in the Gas Operations Risk Register.[21] Based on the risks identified, PG&E develops a risk response plan that assesses the course of action for each risk: accept, reduce, transfer, avoid.

Using the response plan data and other information, PG&E develops an Asset Management Plan (AMP) to describe for each asset family the current

[21] The Gas Operations Risk register is attached as a workpaper to PG&E's testimony. Exh. PG&E-1 at 4-7.

condition of the asset, desired future condition of the asset, key risks for the asset, and mitigation plan to reduce the identified risks. The AMP includes metrics (Key Performance Indicators) to measure the progress of the mitigation programs, has a five-year planning horizon, and is updated annually.

To perform investment planning, PG&E uses risk classifications (*e.g.*, mandatory or compliance) and a risk-informed budget allocation (RIBA) process, which produces a risk score based on relevant safety, environmental, and reliability risks factors. Similar to the RET process, SMEs will revise the RIBA score for each program accordingly. Since the last rate case, PG&E has revised its method for calculating the RIBA score to make the process consistent with its company-wide scoring criteria. PG&E uses documentation from IPP risk management processes, including the RIBA master file and related charts, to support its forecast decisions for the instant rate case.[22]

PG&E also notes that its 2019 GT&S application and first RAMP were prepared concurrently and asserts that, pursuant to the Scoping Memo, protests concerning its risk assessment methodology are outside the scope of this proceeding. Specifically, the Scoping Memo provides that "[t]he GT&S rate case should not evaluate PG&E's risk methodology or be a forum to propose changes or alternatives to the risk methodology including models."[23] In addition, PG&E does not attempt to demonstrate that its forecasts optimize resources because a settlement in the S-MAP proceeding, which concerns the development of a

[22] Exh. PG&E-1 at 4-1 to 4-16.

[23] Scoping Memo at 7.

quantitive process for assessing the cost benefits of reducing risks, was formulated after PG&E had filed its 2019 GT&S application.[24]

### 4.1. Intervenors

Cal Advocates argues that PG&E's risk management process unduly relies on subjective analysis, rather than a quantitative risk assessment methodology, the best practice in the industry.[25] Specifically, Cal Advocates argues that PG&E's RIBA scoring methodology should be phased-out from its risk management process.[26] Cal Advocates asserts that during the hearing, PG&E did not commit to transition to the S-MAP and RAMP processes, which use quantitative tools, before the next rate case. Thus, to ensure the PG&E uses a quantitative process to develop its GT&S forecasts for its next rate case, Cal Advocates requests that the Commission direct PG&E transition its risk management assessment approach to its RAMP and S-MAP processes.[27]

TURN argues that PG&E's risk assessment process should not only identify projects that will mitigate safety risks on its gas transmission system, but also demonstrate that reducing such risks will produce optimal safety improvements in relation to implementation costs. TURN argues that many of PG&E's programs are justified based on vague assertions of a need for safety without a showing that the requested programs are a cost-effective use of ratepayer funds.

For example, TURN asserts, in the prior rate case, PG&E asserted that, for safety purposes, it needed funds for its Normal Operating Pressure Reduction

[24] PG&E Opening Brief at 4-1.

[25] Cal Advocates Opening Brief at 11.

[26] *Id.* at 13.

[27] *Id.* at 14-15.

and Direct Assessment programs. However, in explaining why it performed virtually no work for those programs in the instant rate case, PG&E asserts that the programs were not needed for safety purposes. Thus, TURN asserts that the existence of some safety benefits does not mean that that all of the work that PG&E requests is a high enough priority to justify increasing rates. Accordingly, TURN recommends that the Commission consider this gap in PG&E's risk assessment process when it evaluates PG&E's proposed work pace and forecast for its programs.[28]

### 4.2. PG&E Response

PG&E proposes to continue to use and improve its RET and RIBA processes until the methodology developed in the S-MAP proceeding is finalized and can be used in PG&E's RAMP filing.[29]

### 4.3. Discussion

We find that given the timing between the 2019 GT&S application and the 2019 RAMP filing, it was reasonable for PG&E to use the RIBA and RET risk management methodologies and procedures to identify, scope, and forecast risk management activities for the 2019 GT&S rate case cycle. As noted in section 3, this decision adopts the 2022 attrition year, primarily to ensure the PG&E is able to use the RAMP process and S-MAP procedures in subsequent rate cases to identify, scope and forecast risk management activities for its GT&S utility assets.

Pursuant to SB 705,[30] which addressed gas safety policies, the Commission instituted R.13-11-006, wherein it developed the RAMP process and S-MAP procedures to, among other things, ". . . incorporate a process that focuses on

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[28] TURN Opening Brief at 37-41.

[29] PG&E Opening Brief at 4-7.

[30] SB 705 was codified as §§ 961 and 963 by Chapter 522 of the Statutes of 2011.

safety, assessing the risks relevant to the utility operations, and ensuring that the ratepayer-funded revenue requirement that the utility is requesting can manage and mitigate those risks in a cost-effective manner."[31] The Commission also held that this process should be incorporated in a utility's rate case because that is the proceeding ". . . in which the revenue requirement is developed and adopted for each energy utilities' operations, this is the appropriate place to start to 'take all reasonable and appropriate actions necessary to carry out the safety priority of this paragraph consistent with the principle of just and reasonable cost-based rates.'"[32]

Accordingly, we direct PG&E to restructure its current risk management procedures to incorporate its Commission-authorized RAMP process and S-MAP procedures in time to integrate the results of the RAMP into the next rate case that modifies the revenue requirement for PG&E's GT&S utility assets. PG&E must file a Tier 1 Advice Letter describing the transition process including milestones and deadlines.

## 5. Natural Gas Storage Strategy (NGSS)

### 5.1. Background

PG&E asserts that when its three storage facilities—McDonald Island, Los Medanos and Pleasant Creek—were commissioned in the 1960s and 1970s, the demand for natural gas was growing and supply from in-state fields was declining. PG&E's storage fields were funded by its bundled customers and, at that time, were the only storage facilities connected to its transmission system. PG&E states that, initially, the sole purpose for its storage fields was to provide

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[31] D.14-12-025 at 10.

[32] D.14-12-025 at 5 (citing § 963(b)(3)).

reliability services, but eventually it also used the fields to provide commodity price management services, which allows lower-priced gas to be stored and used when gas prices are higher.

By the end of the 20th century, PG&E states that its storage capacity began to exceed its reliability needs. In addition, Independent Storage Providers (ISP), whose storage fields have a lower cost structure and are constructed with more modern technology, were permitted to connect to and operate on PG&E's transmission system. Nevertheless, PG&E asserts, the excess storage capacity at its storage fields was beneficial to core customers, particularly in the 1990s and 2000s, because natural gas prices were high and volatile.

By 2008, however, PG&E asserts that the benefits from the excess capacity began to wane because the price for natural gas had significantly declined while storage capacity grew. PG&E asserts that spot prices at several gas hubs declined from an average of $8.86 per Million British Thermal Units (MMBtu) in 2008 to $2.52 per MMBtu in 2016. Importantly, the marginal value of the spread between summer and winter gas prices had also declined from $0.715 in 2008 to $0.199 in 2017. As for supply, PG&E asserts that more ISPs, such as Gill Ranch and Central Valley Storage, came online in Northern California.

PG&E asserts that the benefits associated with it having excess capacity will continue to decline because the demand for natural gas in California is projected to decline by 1.4 percent from 2016-2035, even though moderate increases in demand are projected for the residential, small commercial, and transportation sectors.[33] PG&E assert that, pursuant to greenhouse gas (GHG) legislation in California, after 2035, the demand for natural gas will continue to

[33] Exh. PG&E-1 at 11-11.

decline, putting more downward pressure on the spread between summer and winter gas prices.

Aside from the declining value for the price commodity service, PG&E states that compliance with newly enacted governmental rules influenced its NGSS proposal. Specifically, PG&E asserts that on May 19, 2018, the California Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR) implemented new rules for storage service providers (DOGGR May 19 Rule). To comply with the new rules, PG&E asserts that it will be required to retrofit its wells and perform biennial inspections, both of which will be expensive and intermittently "reduce the overall capacity of PG&E's storage facilities by as much as 40 percent."[34]

Thus, after PG&E weighed the cost it would incur to maintain the price commodity services with the benefit that the service would provide to ratepayers, PG&E concluded that it should "cede the business of firm storage-based price management services to the ISPs" and revise its existing gas storage services to focus on reliability, as discussed below.[35]

### 5.2. Overview of PG&E's NGSS

PG&E argues that, to use its storage assets to provide both reliability and price commodity services after it complies with new DOGGR rules, it would be required to build and contract for more storage capacity, which includes drilling 33 new wells at a cost of $179 million and spending $163.9 million to purchase an existing storage facility with 300 MMcf/d of withdrawal capacity.[36] In addition,

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[34] Exh. PG&E-1 at 11-6.

[35] PG&E Opening Brief at 11-4.

[36] Exh. PG&E-1 at 11-6.

PG&E would be required to spend $309 million to retrofit all its wells and $131 million for other safely regulations. This approach would require a present value revenue requirement of $4.89 billion over 20 years.[37]

Thus, as an alternative to maintaining its current storage services and related inventory levels, PG&E proposes to exit the commercial storage market and reduce storage holdings to the amount necessary for it to provide reliability services, such as managing unplanned outages and inventory fluctuations.

To that end, PG&E proposes to size its storage assets using a reliability supply standard (Reliability Standard), which is comprised of certain demand requirements, as discussed below. To meet the demand requirements identified in PG&E's proposed Reliability Standard, PG&E proposes a supply strategy that is outlined in a MOU, executed between it, several ISPs, and TURN.

As part of the supply strategy, PG&E proposes to restructure its storage asset holdings so that it will store, withdraw, and inject the requisite natural gas to provide Core Firm Service and meet a portion of supply requirements of the Reliability Standard. PG&E estimates that the present value revenue requirement for the NGSS is $3.38 billion, which PG&E asserts, is a $1 billion savings over the next 20 years in comparison the to the cost to maintain the capacity necessary to provide the price commodity service.[38] PG&E's estimated savings is based, in part, on PG&E's proposal to decommission the Los Medanos and Pleasant Creek fields so that PG&E does not incur costs to retrofit them to comply with the new DOGGR rules.

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[37] Referred to as the "Status Quo" scenario.

[38] PG&E Opening Brief at 11-3.

In sum, to switch to a reliability-focused storage service strategy, PG&E proposes to (1) implement a new reliability supply standard, (2) modify its storage services, and (3) restructure its asset holdings. Details of each aspect of the proposal are discussed below.

### 5.3. Reliability Supply Standard

#### 5.3.1. PG&E's Proposal

PG&E's proposed Reliability Standard uses specific demand components to identify the supply resources, including storage, that are necessary to operate its gas system. PG&E asserts that the demand components were derived through the MOU negotiation process, discussed above. PG&E asserts that the Reliability Standard has six demand components, three of which represent customer classes: Core, Electric Generation, and Industrial. PG&E forecasts the demand for Industrial Customers using the average daily winter demand. For Core and Electric Generation Customers, PG&E's forecast uses the one-day-in-ten-year (one-in-ten) peak standard. PG&E states that the Commission has allowed the one-in-ten peak standard to be adopted in other instances including in D.06-07-010, which determined the level of PG&E's intrastate pipeline capacity and firm storage withdrawal capacity, among other things. Of the remaining three demand components, two are for new storages services, Inventory Management and Reserve Capacity, which will be discussed in the following sections.

In total, PG&E asserts that the withdrawal capacity for its system-wide Reliability Standard should be 4,616 million cubic feet per day (MMcf/d). A breakdown of each demand component is below in Table 1.[39]

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[39] PG&E Opening Brief at 11-6, Table 11-1.

**Table 1 – Composition of Demand for System Supply Reliability Standard**

| Line No. | Demand Component | Volume (MMcf/d) | Basis for Value |
|---|---|---|---|
| 1 | Core | 2,493 | 1-day-in-10-year demand |
| 2 | Electric Generation | 928 | 1-day-in-10-year demand |
| 3 | Industrial | 522 | Average daily winter demand |
| 4 | Off-system and shrinkage | 123 | Firm delivery obligations; calculated shrinkage |
| 5 | Inventory Management | 300 | Per PG&E proposal |
| 6 | Reserve Capacity | 250 | Per PG&E proposal |
| 7 | Total Supply Reliability Demand | 4,616 | |

### 5.3.2. Intervenors

Intervenors that protested PG&E's Reliability Standard argue that the Commission should either reject or revise the forecast for certain demand components.[40] Calpine argues that the forecast for the Core and Electric Generation demand components should be based on information in the California Gas Report, which forecasts Electric Generation demand using the average daily winter demand under one-in-ten-year cold-and-dry conditions.[41] Calpine asserts that the California Gas Report provides a transparent forecast from an independent resource that was supervised by the Commission and California Energy Commission.[42] In contrast, Calpine asserts, the forecast for core demand in PG&E's forecast is arbitrary as it was negotiated by the parties to the MOU.[43] Calpine argues that PG&E's demand estimate for Electric

[40] CSU Opening Brief at 8-9; Calpine Opening Brief at 21-23; Commercial Energy Opening Brief at 18; Indicated Shippers Opening Brief at 8-9; OSA Opening Brief at 8-12.

[41] Calpine Opening Brief at 21-23.

[42] *Id.* at 22.

[43] *Id.* at 21.

Generation is overstated because it is 40 percent higher than the estimate in the 2018 California Gas Report.[44]

Commercial Energy argues that PG&E overstated its forecast for the core demand component because it is 13 percent higher than the recoded system peak year for the previous GT&S proceeding and inconsistent with PG&E's throughput analysis for the rate case period, as PG&E asserts that core demand will decline.[45] Also, Commercial Energy argues that the demand for Electric Generation customers, which cause the majority of imbalances, has historically been three times lower (i.e., 1,300 thousand decatherms per day ) than PG&E's estimate.[46]

Second, some intervenors argue that pursuant to D.06-09-039, as affirmed by D.18-06-028, the Reserve Capacity demand component should be excluded from the Reliability Standard.[47] SCGC and CSU argue that PG&E's proposal is inconsistent with the mandatory sizing requirements that D.06-09-039 sets forth for backbone transmission and storage systems.[48] SCGC argues that in D.18-06-028 the Commission held that the one-in-ten-cold-year standard accounts for emergencies, thus, providing additional reserve capacity would be a redundancy that should be disallowed.[49]

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[44] *Id.* at 23.

[45] Commercial Energy Opening Brief at 18.

[46] *Id.* at 32.

[47] CSU Opening Brief at 8-9; Indicated Shippers Opening Brief at 29; SCGC and City of Palo Alto Opening Brief at 12-13.

[48] CSU Opening Brief at 8-9; SCGC and City of Palo Alto Opening Brief at 9-12.

[49] SCGC and City of Palo Alto Opening Brief at 12-13.

Similarly, Calpine argues that the Reserve Capacity and Inventory Management services should be removed from the Reliability Standard because they represent supplies of stored gas, rather than the demand for flowing supplies of natural gas.[50] Said another way, Calpine asserts that these services represent supplies of stored gas that PG&E would have the option to access, rather than demand for natural gas that must be provided on the peak-load day.[51] Accordingly, Calpine argues that if the Commission adopts PG&E's one-in-ten peak year standard, the total Reliability Standard should be 4,066 MMcf/d, which excludes the Inventory Management and Reserve Capacity demand components.[52]

Cal Advocates does not oppose the Reliability Standard if the Commission adopts the NGSS.[53] TURN and Joint ISPs are signatories to the MOU and support PG&E's Reliability Standard.[54] Joint IPSs argue that, under the NGSS, PG&E will replace two of its smaller gas storage fields, with a combined storage capacity of 18 Bcf, with the combined capacity from the Joint ISPs' facilities, which is 130 Bcf.[55]

### 5.3.3. PG&E's Response

PG&E disagrees with intervenors' contentions that the Reliability Standard is at odds with D.06-09-039 or D.18-06-028. PG&E asserts that D.06-09-039 was issued pursuant to R.04-01-025, which did not address intraday gas system

[50] Calpine Opening Brief at 23-25.

[51] *Id.* at 23.

[52] Calpine Opening Brief at 24.

[53] Cal Advocates Opening Brief at 100.

[54] TURN Opening Brief at 148; Joint ISPs Opening Brief at 7.

[55] Joint IPS Opening Brief at 6.

balancing issues, the main purpose of the Inventory Management service. Also, PG&E argues, in D.06-09-039 and D.18-06-028, the Commission did not establish a peak day planning standard for storage facilities and, therefore, that decision does not apply to the NGSS.[56]

PG&E disagrees with intervenors who contend that the forecast for the Core and Electric Generation demand components are inconsistent with 2018 California Gas Report. PG&E argues that its forecast for the Core and Electric Generation demand components are based on the 2016 California Gas Report, as that report was available at the time that the MOU was drafted. PG&E argues that its estimate for Electric Generation demand, as adopted in the MOU, is lower than the 2016 California Gas Report because the estimate in the MOU accounts for the higher than average heating value of the gas on PG&E's gas system.[57] Also, PG&E asserts that the California Gas Report is using a different standard, one-in-ten year cold-and-dry conditions, rather than a peak day demand. PG&E asserts that over the last year, its daily Electric Generation demand varied from 1,318 MMcf/d to 243 MMcf/d; thus, its estimate of 922 MMcf/d is reasonable.[58] PG&E argues that the difference between its estimates and the 2018 California Gas Report's estimates for Core demand is only 1.8 percent (46 MMcf/d) and, therefore, immaterial.

#### 5.3.4. Discussion

As a threshold matter, we find that PG&E's proposal to eliminate its commodity price service and move to a reliability-only focused storage strategy

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[56] PG&E Reply Brief at 11-3 and 11-4.

[57] PG&E Opening Brief at 11-13.

[58] *Id.* at 11-13 and 11-14.

is just and reasonable. In complying with the DOGGR rule, PG&E will lose 40 percent of its withdrawal capacity.[59] Thus, if PG&E continues to provide a commodity price service, it will need to replace the lost capacity. PG&E asserts that replacing 40 percent of the lost capacity will require it to dig new wells and contract with ISPs for storage service, all of which would yield a present value revenue requirement over 20 years that is $1 billion more than the revenue requirement for the NGSS.[60]

As an alternative to replacing the lost capacity, PG&E proposes to eliminate the commodity price service. No party disputes that the cost of maintaining the commodity price service outweighs the associated benefits as the marginal price between the summer and winter months has substantially declined. In addition, customers that prefer to use the commodity price service can contract with ISPs because, as PG&E and the ISPs note, Joint ISPs have 130 Bcf of available storage capacity.

With respect to the Reliability Standard, we find that PG&E's method for estimating the demand components is reasonable. We disagree with the intervenors who contend that the Core and Electric Generation components should be identical to the 2018 California Gas Report. The difference between 2018 California Gas Report's forecast of Core demand during the rate case period and PG&E's estimate is immaterial (*i.e.*, 1.8 percent or 46 MMcf/d). While the difference between the 2018 California Gas Report's estimates for Electric Generation during the rate case period and PG&E's estimate is substantial, we find PG&E's estimate more credible for purposes of establishing its Reliability

[59] Exh. PG&E-1 at 11-15, 11-24 (Table 11-3).

[60] PG&E Opening Brief at 1-1.

Standard because PG&E's estimate is tailored to address its unique system attributes. Moreover, using a higher demand estimate is a conservative approach that is reasonable given the extent to which the NGSS will change PG&E's operations and the fact that the objective of the Reliability Standard is to ensure that PG&E has enough supply to meet peak demand during system outages and other emergencies.

We disagree with intervenors' contention that Inventory Management and Reserve Capacity should not be demand components. The objective of the Reliability Standard is for PG&E to be able to meet load requirements for gas service on a day when there is a high customer demand for gas, a major system outage on its gas transmission system and a significant storage inventory imbalance. We find that all of these objectives are reasonable requirements for PG&E to use as a basis for ensuring that it will be able to reliably operate its integrated transmission and storage system. Also, as discussed below, we disagree with the intervenors' contention that D.06-09-039 or D.18-06-028 would prohibit the Commission from adopting PG&E's Reliability Standard. Accordingly, we adopt PG&E's Reliability Standard as stated above in Table 1.

### 5.4. Inventory Management

#### 5.4.1. PG&E's Proposal

PG&E states that, if the Commission adopts its NGSS, it will need to implement a process to resolve intraday inventory imbalances on its backbone transmission system. PG&E states that hourly imbalances between demand and supply can cause storage inventory and pipeline operating pressures to fluctuate in a manner that is unsafe. Thus, PG&E asserts that it must resolve the inventory imbalances so that the pressure on its backbone transmission system remains within safe operating limits. PG&E states that, historically, it has managed intraday inventory imbalances by using storage capacity that was temporarily unused by core customers and by using available park and lend volumes. However, PG&E asserts that under the NGSS, it will no longer have the requisite unused storage volumes as it plans to reduce the amount of natural gas stored for core customers at its storage fields from 33 Bcf to 5 Bcf.[61] Accordingly, PG&E proposes to implement the Inventory Management service, which will sequester enough storage capacity to resolve intraday fluctuations on its backbone transmission system. PG&E states that the Inventory Management service will support hourly imbalances, shrinkage imbalances, pipeline-to-pipeline imbalances, and ISP imbalances, among other issues.

PG&E determined the amount of storage capacity needed for the Inventory Management service by analyzing the sendout data for each hour of the days between December 2010 and February 2016. For that time period, PG&E identified the instances where the customer demand and gas supply differed. For 98 percent of the deviations, PG&E's analysis demonstrated that 300 MMcf/d of withdrawal capacity and 200 MMcf/d of injection capacity would be sufficient to prevent hourly deviations outside of the acceptable inventory range of 3.9 to 4.3 Bcf.[62] The MOU provides that PG&E will coordinate with ISPs to cover the 2 percent of instances when Inventory Management volumes would not be able to resolve the deviations between customer demand and supply, and it will invoke Operational Flow Orders (OFO) and Emergency Flow Orders (EFO), as necessary. PG&E proposes to set aside 5.0 Bcf of

[61] Exh. PG&E-1 at 10-10.

[62] PG&E Opening Brief at 11-42.

inventory capacity, 300 MMcf/d of withdrawal capacity and 200 MMcf/d of injection capacity for the Inventory Management service.[63]

### 5.4.2. Intervenors

Calpine and Indicated Shippers argue that the capacity that PG&E requests for the Inventory Management service is unduly excessive.[64] Calpine asserts that PG&E's Inventory Management service operates by using upper and lower limits for inventory levels on PG&E's backbone system, and these levels are managed in real time throughout the day. Calpine and Indicated Shippers argue that, because the lower inventory limit that PG&E used to estimate capacity requirements for Inventory Management is unduly low, PG&E overstated the amount of capacity that it requires for the Inventory Management service.[65]

According to Calpine's analysis of the study that PG&E used to set the inventory parameters, Calpine argues that PG&E's starting lower and upper parameters should be 4.2 Bcf and 4.5 Bcf, respectively, rather than 4.1 Bcf and 4.3 Bcf.[66] By increasing the inventory parameters, Calpine and Indicated Shippers argue, PG&E could operate the Inventory Management service with 100 MMcf/d injection and withdrawal capacity, rather than 300 MMcf/d withdrawal capacity and 200 MMcf/d of injection capacity as PG&E proposes.[67] In addition, Indicated Shippers argues that its study of the hourly storage variability ratios between 2005-2007 and 2010-2017 also demonstrates that

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[63] *Id.* at 11-42 to 11-43.

[64] Calpine Opening Brief at 43-49; Indicated Shippers Opening Brief at 31-33.

[65] Calpine Opening Brief at 47; Indicated Shippers Opening Brief at 33.

[66] Calpine Opening Brief at 45-46.

[67] Calpine Opening Brief at 46, 49; Indicated Shippers Opening Brief at 31-33.

100 MMcf/d of withdrawal and injection capacity is appropriate for the Inventory Management service.[68]

Commercial Energy argues that PG&E's estimate for the amount of storage capacity that it needs for the Inventory Management service should consider that Electric Generation customers cause most instances of daily imbalances on PG&E's gas transmission system.[69] Also, Commercial Energy asserts that PG&E's estimate does not adequately consider that noncore customers are subject to curtailment and, therefore, PG&E may curtail noncore customers to resolve inventory imbalance issues, rather than rely on Inventory Management. Similarly, Indicated Shippers argue that PG&E's estimate does not consider that, pursuant to the MOU, the ISPs' storage capacity is available to help PG&E resolve inventory imbalances.[70]

Cal Advocates does not oppose PG&E's proposal to establish the Inventory Management service if the Commission adopts the NGSS.[71] TURN and the Joint ISPs support PG&E's proposal. TURN argues that, if the NGSS is adopted, PG&E will need the Inventory Management service to reliably operate its gas transmission and storage system, particularly since PG&E's storage capacities will be substantially reduced.[72] Furthermore, TURN argues, PG&E has demonstrated that using higher inventory parameters would degrade services on PG&E's transmission lines, among others.[73] Joint ISPs assert that, pursuant to

[68] Indicated Shippers Opening Brief at 31-32.

[69] Commercial Energy Opening Brief at 32.

[70] Indicated Shippers Opening Brief at 33.

[71] Cal Advocates Opening Brief at 105-106.

[72] TURN Opening Brief at 150.

[73] *Id.* at 153.

the MOU, they will coordinate with PG&E on a daily basis to address the small percent of instances (*i.e.*, 2 percent) when the Inventory Management service will not be able to completely resolve an inventory balance deviation.[74]

#### 5.4.3. PG&E's Response

PG&E argues that it considered customer curtailments but declined to use it as the sole approach for handling hourly balance issues because its system and tariff are not designed to implement same day, hourly curtailments.[75] Nevertheless, PG&E argues, the high frequency with which curtailments would need to be called would be unreasonably disruptive to noncore customers.[76]

PG&E disagrees with intervenors' contention that it should increase the lower inventory balance parameter to 4.2 Bcf. PG&E argues that, because customers frequently over-deliver and under-deliver gas, PG&E does not have complete control over its beginning inventory levels. PG&E states that if it has not called an OFO the day before, the imbalances caused by the over- or under-delivery will need to be resolved using the capacity levels proposed for the Inventory Management service as unused core storage inventory will no longer be available.

Similarly, PG&E disagrees with intervenors' contention that it should increase the upper inventory parameter to 4.5 Bcf because, PG&E argues, doing so would degrade service on PG&E's gas transmission system. Specifically, PG&E asserts that, because gas is compressible, the pressure in the storage fields impacts the pressure on the entire gas pipeline system and vice versa. Thus,

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[74] Joint ISPs Opening Brief at 5.

[75] PG&E Opening Brief at 11-50.

[76] *Id.* at 11-50.

when storage inventory increases, the upstream compressor stations will slow down or stop, creating imbalances on PG&E's and other upstream pipeline systems.[77]

#### 5.4.4. Discussion

We find that the Inventory Management service is a reasonable approach for PG&E to use to manage intra-day and day-ahead inventory fluctuations on its integrated gas pipeline and storage system. As part of the NGSS, the unused inventory, financed by core customers, that PG&E previously used to manage intraday inventory will no longer be available for that purpose. Thus, setting aside storage and pipeline capacity to provide that function is reasonable.

With respect to the inventory levels, we disagree with intervenors' contention that PG&E should use higher upper and lower inventory balance parameters. We find persuasive PG&E's argument that increasing the beginning inventory level would degrade not only its systems, but also other upstream pipeline systems.

While we disagree with intervenors who contend that PG&E should use its ability to curtail non-core customers as the sole method for managing all inventory imbalances, we find that PG&E could improve its ability to take advantage of the curtailment option. PG&E states that its system and tariff are not designed to handle hourly curtailments. Thus, for the next rate case, we direct PG&E to offer a proposal for improving its curtailment process and to state whether and to what extent using an hourly curtailment process would allow it to offset some of the capacity volumes that are reserved for the Inventory Management service.

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[77] *Id.* at 11-52 and 11-53.

Further, in disagreeing with Commercial Energy's request to conduct a Demand Response pilot,[78] PG&E argues, in part, that a "mechanism already exists to curtail load," and that "ensuring curtailment compliance would be very difficult and expensive."[79] Having a Gas Demand Response program could allow customers to voluntarily curtail load, giving PG&E more options to operate its system while reducing unwanted service disruptions. Accordingly, we direct PG&E to file an application on or before January 30, 2020, with a proposal to implement a Gas Demand Response program.

### 5.5. Reserve Capacity

#### 5.5.1. PG&E's Proposal

PG&E states that, currently, it manages equipment outages by using unused core storage capacity and by shifting intraday park and lend withdrawals and injections. However, as part of the NGSS, PG&E states that the unused core inventory that PG&E previously used to resolve supply issues caused by equipment outages will be reduced by 80 percent and, therefore, no longer available for that purpose.[80] PG&E asserts that the Reserve Capacity service will provide its system with emergency intraday supply of natural gas in case of a significant, unplanned equipment outage or other supply problem.

Based on certain outage scenarios,[81] PG&E estimates that Reserve Capacity will require a withdrawal capacity of 250 MMcf/d and an injection capacity of

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[78] Commercial Energy Opening Brief at 10-15.

[79] PG&E Opening Brief at 10-16.

[80] PG&E Opening Brief at 11-39.

[81] Namely, a well and/or dehydrator outage with an impact of 100 MMcf/d, a single transmission compressor unit outage with an impact of 200 MMcf/d, a pipeline outage on Lines 400 and 401 south of the Delevan Station with an impact of 200 MMcf/d, and a pipeline

25 MMcf/d, both of which will require PG&E to maintain 1.0 Bcf of inventory capacity.[82] With this configuration, PG&E asserts that it would have sufficient inventory coverage for four days and a 40-day replenishment period. PG&E states that an outage event that is beyond the capability of Reserve Capacity would be handled by other means, such as through same day EFO and curtailments.

#### 5.5.2. Intervenors

Some intervenors argue that Reserve Capacity is unnecessary. Indicated Shippers argues that PG&E has never used this service in the past and will not need it in the future as the projected gas throughput on PG&E's gas transmission system is forecasted to decline.[83] Indicated Shippers and Calpine assert that PG&E admits that it has previously relied on outside storage resources to ensure reliability; thus, they argue that PG&E's analysis should include the additional 30.5 Bcf of storage inventory and 2,300 MMcf/d of withdrawal capacity that ISPs will make available to PG&E pursuant to the MOU.[84] Also, Indicated Shippers and SCGC argue that, in the unlikely event that a system emergency causes a shortfall in capacity such that PG&E is unable to meet average customer requirements, PG&E could issue an OFO and curtail customers.[85]

Indicated Shippers argues that PG&E's approach for calculating the capacity levels for Reserve Capacity is flawed. Indicated Shippers assert that

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outage on Line300 north of the Panoche Station with an impact of 250 MMcf/d. *See* PG&E Opening Brief at 11-39, Table 11-2.

[82] PG&E Opening Brief at 11-38 and 11-39.

[83] Indicated Shippers Opening Brief at 30.

[84] Calpine Opening Brief at 40; Indicated Shippers Opening Brief at 30.

[85] Indicated Shippers Opening Brief at 28-29; SCGC Opening Brief at 16-17.

PG&E should have used a "probabilistic risk analysis" to assess the likelihood of equipment failures rather than rely on "devastating" outage scenarios.[86]

SCGC and the City of Palo Alto challenge PG&E's contention that its system is not designed to simultaneously curtail customers and that many noncore customers do not have the staff to implement curtailment requests in a timely manner. They argue that instead of allowing PG&E to impose mandatory capacity services, the Commission should direct PG&E to revise its curtailment rules, given the cost for Reserve Capacity.[87] SCGC and City of Palo Alto also argue that the PG&E's Reserve Capacity service would be costly to customers and, therefore, should not be implemented. They assert that the cost for Reserve Capacity is equivalent to PG&E's estimated cost to source the capacity, which is to build 11 wells at McDonald Island at a cost of $56 million in capital expenditures, among other costs.[88]

Some intervenors assert that, if the Commission adopts PG&E's Reserve Capacity proposal, the Commission should allow noncore customers to opt-out of the service.[89] Under this option, Calpine explains, if PG&E is required to withdraw from its reserve capacity, PG&E would curtail those customers who have opted-out. Calpine disagrees with PG&E's contention that Calpine's opt-out proposal is impractical because, consistent with the MOU terms, the ISPs

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[86] *Id.* at 27-30.

[87] SCGC and City of Palo Alto Opening Brief at 15-16 (citing D.16-07-008, SoCal Gas and SDG&E application to revised curtailment rules.

[88] SCGC at 17. Also, the incremental operations and maintenance costs for the period of 202-2022 would be $23.3 million. *Id.*

[89] CSU Opening Brief at 8-9; Calpine Opening Brief at 41-43; Indicated Shippers at 29.

will provide a substantial amount of core storage capacity that PG&E could use to ensure that its integrated gas transmission and storage system is reliable.[90]

Cal Advocates does not oppose PG&E's proposal to establish the Reserve Capacity service if the Commission adopts the NGSS.[91] TURN argues that, if the NGSS is adopted, PG&E will need the Reserve Capacity service to reliably operate the system as its storage capacity will be substantially reduced.[92] TURN argues that some noncore customers oppose the NGSS because they do not want to pay for storage services that they have been receiving free of charge.[93] The Joint ISPs support PG&E's proposal to establish the Reserve Capacity service.

#### 5.5.3. PG&E Response

PG&E argues that allowing noncore customers to opt-out of Reserve Capacity and, instead, contract with ISPs to provide a similar type of service is unrealistic given the limitations with its technical and administrative operating procedures. PG&E explains that, assuming a customer who opts-out has gas storage available at a respective ISP, PG&E does not have a process that allows ISPs to provide PG&E with "hour-by-hour" service.[94] The current process allows for three intraday nominations, which are not frequent enough to resolve the supply issues that Reserve Capacity is designed to address. Also, PG&E argues that allowing customers to obtain reserve services from ISPs would pose an operational risk to its gas system because the ISPs are located outside of the

[90] Calpine Opening Brief at 42.

[91] Cal Advocates Opening Brief at 105-106.

[92] TURN Opening Brief at 150.

[93] TURN Opening Brief at 152.

[94] PG&E Opening Brief at 11-47.

upstream and downstream pipeline constraint zone; thus, PG&E must maintain a certain level of inventory on hand.[95]

PG&E asserts that there are no viable alternatives to the Reserve Capacity service, including curtailing non-core customers. PG&E asserts that, because the load reductions would occur at the far end of its local transmissions system, curtailments would not be a timely response to a major supply problem, such as equipment outage, on its backbone transmission system. In addition, PG&E asserts that because it does not have control over whether and when customers execute curtailment requests, it is unrealistic for it to rely on curtailments to resolve supply emergencies.

PG&E disagrees with intervenors who contend that it should have used a probabilistic risk analysis, which calculates the likelihood of a supply outage, and economic studies to determine the amount of capacity that it should dedicate to Reserve Capacity and the cost of potential alternatives. PG&E argues that these contentions ignore the fact that PG&E's forecast of the capacity needed for Reserve Capacity was based on types of outages that are common on its system.[96]

#### 5.5.4. Discussion

We find that offering Reserve Capacity services is a reasonable approach for PG&E to use to resolve significant, unplanned equipment outages, among other supply problems. With the implementation of the NGSS, the unused core inventory that PG&E previously used to resolve unplanned supply shortages will no longer be available. Thus, setting aside storage capacity to resolve significant supply problems is reasonable.

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[95] *Id*. at 11-48.

[96] PG&E Opening Brief at 11-56.

We disagree with intervenors who contend that Reserve Capacity is unnecessary because PG&E did not use it in the past. This argument ignores that, in implementing the NGSS, PG&E will not have unused core storage capacity on hand to resolve significant supply issues.

We find that curtailments are insufficient to replace Reserve Capacity for the reasons that PG&E asserted. However, as with Inventory Management, we find that PG&E could improve its ability to use curtailments to facilitate the resolution of supply issues. Thus, for the next rate case, we direct PG&E to offer a proposal for improving its curtailment process and to state whether and to what extent using an hourly curtailment process would allow it to offset some of the inventory volumes that are allotted for the Reserve Capacity service.

### 5.6. Existing Storage Services

#### 5.6.1. PG&E's Proposal

In connection with the NGSS, PG&E proposes to eliminate the Standard Firm Storage services from its tariff (*e.g.*, Gas Schedule G-SFS) and to retain its park and lend tariffs and negotiable storage tariffs, for limited purposes. PG&E also proposes to reduce the amount of storage capacity that is available for Core Firm Services to 5,175 thousand decatherms per day (MDth) for storage capacity, 25 MDth/d of maximum injection capacity, and 318 MDth/d of maximum withdrawal capacity during December to February, and 159 MDth/d during November and March.[97] PG&E states that the reduction in storage capacity will occur over a two year period, during which, the inventory storage levels at PG&E's storage fields will be reduced in multiple phases.

[97] Exh. PG&E-1 at 11-24.

PG&E states that, of the core customers' 2,580 MDth/d portion of the Reliability Standard, PG&E's storage fields will supply 318 MDth/d of withdrawal capacity, interstate pipeline capacity will source 1,255 MDth/d, and the remaining capacity will be supplied from Citygate and the Joint ISPs' storage facilities.[98] PG&E states that its Core Gas Supply Department (CGS) and the Core Transport Agents (CTA) will be required to contract with the Joint ISPs to supply the remaining storage capacity for core customers.

#### 5.6.2. Intervenors

OSA argues that PG&E's proposal to have core customer rely on ISPs to provide the balance of the capacities that they are required to hold under the Reliability Standard could cause reliability issues. OSA argues that, because ISPs have a contractual, rather than regulatory, obligation to serve core customers, the ISPs' obligations are less firm than PG&E's.[99]

OSA argues that, if the NGSS is approved, the Commission should require that ISPs follow certain conditions, including maintaining "[s]tandby power generation capacity that assures full contracted volumes can be withdrawn during electric power supply outages."[100] In addition, OSA argues that the ISP's should be required to meet certain creditworthiness requirements such as having an investment grade rating by Standard and Poor's or Moody's. Also, OSA argues that, ISPs should be required to follow certain recommended industry best practices, such as the American Petroleum Institute (API) Recommended Practice (RP) 1173. OSA disagrees with the ISPs' argument that API RP 1173 is

[98] The amount of capacity that will be supplied by ISPs and purchases at the Citygate is designated confidential. Exh. PG&E-2 at 19-7.

[99] OSA Opening Brief at 14.

[100] *Id.* at 16.

only applicable to pipelines, rather than storage facilities, because PG&E has adopted this standard for its storage facilities. OSA admits that the ISPs are required to file an Operator's Safety Plan with the Commission annually but argues that the Commission's annual review is only concerned with minimum regulatory compliance with applicable general orders and governmental regulations.[101] Specifically, OSA argues that the Commission's Safety and Enforcement Division's (SED) audit of the Safety Plans is inadequate as SED's review focuses on whether the plan in adequate, not on whether the plan has been adequately implemented.[102]

In addition, OSA argues that the Commission should implement other safety related requirements. OSA argues that PG&E and the ISPs should be required to develop a safety management system framework that includes implementing API RP 1173 and that PG&E and the ISPs should report on the implementation status of the framework on an annual basis. OSA argues that PG&E and the ISPs should be required to adopt the safety metrics that were developed in the S-MAP proceeding "as applicable to their specific operations, for reporting to the Commission at a defined frequency," among other suggestions.[103] Finally, OSA argues that ISPs are subject to less Commission oversight than PG&E and are driven by economic interests and charging market-based rates; thus, ISPs are less reliable than PG&E.[104]

The Joint ISPs disagree with OSA's contentions. Joint ISPs argue that PG&E will have more flexibility by having some of the storage requirements of

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[101] *Id.* at 19.

[102] OSA Comments on Proposed Decision at 1-3.

[103] OSA Opening Brief at 21.

[104] *Id.* at 10, 20.

core customers spread across four separate Joint ISP facilities.[105] Joint ISPs assert that with their combined inventory and withdrawal capacity of 130.5 Bcf and 2,300 MMcf/d, respectively, they offer a considerably larger capacity (*i.e.*, 18 Bcf and 400 MMcf/d) than the storage facilities that PG&E seeks to retire.[106] Thus, they have more than enough capacity to supply the 862 MMcf/d of capacity that they agreed to provide to PG&E pursuant to the MOU and to fulfill their other contractual obligations. Also, Joint ISPs argue that in the event that core customers are unable to obtain the requisite gas from an ISP on a particular day, they have alternative means for getting supply, including from the other three ISPs.

The Joint ISPs argue that, because they are public utility gas corporations that are subject to the Commission's jurisdiction, there is no need for the Commission to impose additional regulatory requirements. The Joint ISPs assert that PG&E's CGS already subjects the ISPs to a financial strength analysis, insurance review, and certain operational threshold requirements; thus, if the Commission approves the NGSS, it should not require that ISPs adhere to additional credit requirements to provide gas storage services to core customers.[107]

With respect to OSA's safety concerns, Joint ISPs argue that they have "robust" safety programs and protocols that are subject to audit, and have been audited, by the SED.[108] Joint ISPs disagree with OSA's contention that their

[105] Joint ISPs Opening Brief at 5.

[106] *Id.* at 6. Joint ISPs state that the will build out or operate at their full certified capacity if there is a market demand to do so. *Id.* at 9.

[107] Joint ISPs Opening Brief at 11.

[108] *Id.* at 15.

safety programs should include the implementation of API RP 1173 because that recommended practice does not apply to storage operators. Moreover, Joint ISPs argue, they already comply with AP RP 1171, a recommended practice that specifically applies to the design, construction, operation, monitoring, and documentation practices of underground storage facilities.

In addition, Joint ISPs disagree that they should be required to submit the metrics identified in the S-MAP proceeding because they already submit the applicable metric to the Commission during the SED audits. OSA clarifies that the metrics that the Joint ISPs currently submit are not the S-MAP metrics.[109]

#### 5.6.3. Discussion

We find that PG&E's proposals to eliminate its Standard Firm Storage Service from its tariff and reduce the amount of Core Firm Service that it offers to its core customers is reasonable, subject to the conditions described below. As noted above, this decision grants PG&E's request to redesign its gas storage operations to focus on reliability and to eliminate the price commodity service. As such, PG&E's Standard Firm Storage Service is no longer necessary.

We find that requiring core customers to obtain from ISPs the storage withdrawal storage capacity beyond what PG&E will provide (*i.e.,* 318 MDth) is reasonable, subject to conditions. The ISPs attest that they maintain gas withdrawal capacity that far exceeds the estimated core demand that the Reliability Standard requires. Further, authorizing PG&E to rely on ISPs to provide firm storage services to meet the reliability standard for core customers is not unprecedented. In D.06-07-010, the Commission authorized PG&E to acquire additional storage resources from ISPs so that PG&E could implement a

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[109] OSA Comments to the Proposed Decision at 1-2.

one-in-ten peak standard for core customers. In that proceeding, PG&E estimated that it would require 100 MDth of additional withdrawal capacity and between two to three MMdth of storage inventory capacity.[110]

In D.06-07-010, the Commission also determined that PG&E would need to resolve issues concerning the solicitation and evaluation of bids from potential storage providers such as:

1. Under what conditions will ISPs be allowed to compete to provide this incremental firm core storage capacity?
2. What process should PG&E follow in determining the kind of storage proposals that should be solicited and which proposals will be required?
3. Should ISPs be required to meet certain reliability standards or be required to maintain sufficient facilities in order to deliver gas to PG&E's core customers under all conditions without relying on PG&E?[111]

To that end, the Commission adopted an unopposed stipulation between PG&E and the active parties in that proceeding to establish procedures for soliciting and evaluating bids from storage providers interested in providing incremental firm storage capacity to PG&E's core customers.[112]

We adopt similar procedures here. While the MOU provides that the ISPs will provide 862 MMcf/d of storage withdrawal capacity, it does not specify the rates, terms, and conditions for providing such capacity. Thus, as a condition to granting PG&E's request to have core customers source the storage withdrawal capacity necessary to meet the Reliability Standard, we direct PG&E to establish the solicitation and evaluation process outlined in Appendix I. The process will

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[110] D.06-07-010 at 7.

[111] D.06-07-010 at 23-24.

[112] D.06-07-010 at 22-27.

require that PG&E (through CGS), Cal Advocates, and TURN (if it chooses to participate) develop a methodology to evaluate bilateral contract proposals between CGS and ISPs, or a Request for Offer (RFO), including a bid acceptance process. Final terms will specify the costs for storage, storage amounts, and withdrawal and injection rates. The objective of the contract and RFO evaluation and solicitation process is for PG&E to negotiate, and Cal Advocates and TURN to approve, the rates, terms, and conditions for the entire capacity that PG&E's core customers will need to purchase from ISPs in order to meet the Reliability Standard. CTAs will negotiate for their customers to procure required amounts of storage.

We agree with OSA that Joint ISPs should be required to maintain standby power generation capacity. We find that maintaining standby power is necessary because if an ISP loses power, it may not be able to provide reliable gas storage services. Accordingly, we direct PG&E and the other parties to include as a requirement in the RFO that Joint ISPs must agree to have standby power generation capacity at the storage fields that serve PG&E's core customers. We also agree with OSA's recommendation that the Joint ISPs should submit S-MAP metrics that are applicable to their storage operations. Accordingly, on we direct the Joint ISPs to submit S-MAP metrics regarding their storage operations on an annual basis, starting on January 30, 2020.

We find that OSA's contention that SED does not audit the ISPs' Safety Plans is partially correct. SED's Risk Safety Assessment department reviews the Safety Plans for compliance with relevant state-mandated statutes and rules, while its Gas Safety and Reliability Branch (GSRB) performs audits to ensure that ISPs have implemented and are in compliance with the Pipeline and Hazardous Materials Safety Administration (PHMSA) rules, which are components of the

Safety Plans. Thus, we direct SED to conduct an analysis to determine the Safety Plan requirements that are not currently audited by GSRB. As part of the analysis, SED shall identify whether it recommends expanding the scope of the GSRB audits of the ISPs' Safety Plans and, if so, when it anticipates expanding the scope and whether it will require additional resources. We direct SED to file a report of its analysis within 90 days of the date that this decision is final.

We share OSA's concern that the rates that ISPs could charge core customers for their share of the 862 MMcf/d of storage withdrawal capacity needed to satisfy the Reliability Standard is uncertain. Because ISPs are considered public utilities,[113] pursuant to Section 451, the Commission has the authority to ensure that each ISP's storage rates are just and reasonable. The Commission's policy for regulating ISPs is predicated on the Commission's understanding that the natural gas storage market in Northern California is competitive and that ISPs will primary serve non-core customers.[114] Thus, the Commission has historically required ISPs to file applications for a Certificate of Public Convenience and Necessity, which, as a condition for approval, requires ISPs to file tariffs that state the price, terms, and conditions for storage service. When ISPs lack market power, the Commission has granted market-based rate authority.[115]

We recognize that with the adoption of the NGSS, at least one of the underpinnings of the Commission's policy will change, as ISPs will provide a significant amount of firm storage services to PG&E's core customers.

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[113] Sections 216 (a) and 222; see also D.10-10-001 at 55, Conclusion of Law 1.

[114] *Lodi Gas Storage, LLC,* 2000 Cal. PUC LEXIS 394 at *106-107, Finding of Fact 25 (D.00-05-048).

[115] *See* D.00.05.048 (authorizing Lodi Gas Storage to charge market-based rate because it lacked market power).

Nevertheless, we are confident that the contract negotiation process discussed above will ensure that ISPs provide adequate storage services at reasonable rates to core customers. However, if the NGSS causes market disruptions that cannot be mitigated by the contract negotiation process, the Commission will revisit its procedures for how we exercise our jurisdiction to ensures that ISP rates are just and reasonable, including but not limited to, requiring IPSs to file applications to establish cost-based rates for storage services provided to core customers.

Lastly, we appreciate OSA's position that this decision should direct the ISPs to revise their safety programs or implement API RP 1173 but we decline to take that step in this proceeding concerning PG&E's GT&S operations. Section 961 (c) requires public utilities that provide gas services to file with the Commission plans that demonstrate, among other things, that the public utilities' gas system operating practices are safe, reliable, and consistent with the best practices in the gas industry. SED is responsible for reviewing these plans and ensuring that ISPs' have implemented applicable best practices. To that end, SED conducts safety audits and annual reviews of each ISP's Safety Plans. Thus, to ensure that the Commission provides consistent safety-related guidance to the ISPs, we will defer to SED's existing audit process. However, while we do not adopt OSA's recommendation here, as we stated in D.18-10-029, the Commission may consider opening a rulemaking to evaluate whether natural gas utilities, including the independent storage providers, should be required to have a safety management procedures and safety culture plan, and if so, what procedures should be included in such a plan.

### 5.7. Core Gas Supply

PG&E's CGS group is responsible for procuring gas, pipeline capacity, and storage capacity to service PG&E's core gas customers. In implementing the

NGSS, the capabilities of PG&E-owned and operated natural gas storage facilities will be reduced. Accordingly, CGS proposes to reduce its allocation from PG&E for core storage capacity and replace the shortfall by increasing its allocation of core storage services with ISPs and increasing its capacity allocations with intrastate pipelines.

In developing its proposal, CGS considered different mixes of transportation and storage and used estimated future rates for each. In particular, CGS consider the following: (1) reducing PG&E core firm gas storage inventory and withdrawal as presented in the MOU, (2) compliance with the Reliability Standard, (3) economics of storage versus transportation by estimated rates for PG&E pipeline capacity, PG&E firm core gas storage, and ISP storage, (4) operational flexibility needed for day-to-day forecast and actual load changes, (5) ISP withdrawal constraints on a high load day, as stated in the MOU, (6) minimum term requirements for seasonal PG&E pipeline capacity, (7) supply availability at northern and southern California Border Locations, and (8) Citygate supply availability on peak load days.[116]

Based on its analysis of the aforementioned issues, CGS proposes to (1) reduce its PG&E Core Firm Service storage allocation by 28,303 MDth to 5,175 MDth, (2) decrease its PG&E firm core gas storage withdrawal capacity by 935 MDth/d to 318 MDth/d, from December-February and by 1,094 MDth/d to 159 MDth/d or November and March, (3) decrease PG&E firm gas storage injection capacity from April to October by 121 MDth/d to 25 MDth/d for November and March. CGS notes that this proposal does not allow it or a CTA to replace their proportionate share of firm storage capacity with anything other

[116] Exh. PG&E-2 at 19-6 (citing Workpapers 19-1, 19-2, 19-3, 19-4, 19-5).

than storage from ISPs or PG&E. With respect to pipeline capacity, CGS proposes to increase its intrastate allocation in November through February and decrease its allocations in March through October. CGS also requires conforming changes to its interstate pipeline capacity planning ranges, as discussed below.

To implement its proposed pipeline capacity changes, CGS requests the following changes to D.15-10-050: (1) increase the winter range maximum to 162 percent of the average annual daily demand so that CGS has to option to purchase more pipeline capacity during the winter months, (2) reduce the March range minimum to 80 percent of the average annual daily demand because with the increase in planned storage withdrawal in March, it may have less need for interstate pipeline capacity that month, (3) allow CGS to use the advice letter process to seek an exception to the capacity planning range minimum if it anticipates a shortfall of no more than 50 MDth/d during a given month.[117]

In addition, to meet the Reliability Standard, CGS proposes that CTAs self-procure firm gas storage from either PG&E or ISPs, rather than rely on the assignments of proposed ISP contract held by CGS. And CGS request that the RFO process set forth in D.06-07-010 is required for approving all ISP contracts, except as noted below.

CGS proposes to remove the RFO process for it to obtain gas storage service from ISPs, as set forth in Ordering Paragraph (OP) 4(a) of D.06-07-010. CGS argues that, given the increase in the amount of gas that it will need to procure from ISPs if the NGSS is adopted, the RFO process is overly restrictive. CGS asserts that the standby power requirement for ISPs should be removed or

[117] Exh. PG&E-2 at 19-13.

replaced because that requirement is unduly prescriptive and CGS can achieve firm storage withdrawal deliveries with specific contract terms or other means.

Because holding sufficient amounts of storage capacity is critical to providing reliability service for core gas customers, CGS proposes that all entities servicing core gas customers (*i.e.,* CGS and CTAs) provide verification of storage procured from an ISP to PG&E's Gas Operations groups demonstrating that each entity's storage holdings comply with the guidelines proposed in Advice Letter 3884-G, which includes filing Form 79-845M.[118]

CGS also notes that, if its proposals are approved, the amount of gas CGS stores with ISPs will increase related to its current holdings, which, in turn will increase the potential loss that PG&E could incur if an ISP defaults. Pursuant to D.08-07-009, the maximum collateral that PG&E can request is equal to the value of one day's gas withdrawal, a value that has no bearing on the measure of actual risk and would be insufficient to cover the financial losses associated with an ISP's default. Accordingly, CGS proposes to change the credit restriction with a requirement that ISPs either: (1) be rated as investment grade by Standard and Poor's or Moody's or (2) provide credit assurance that equals 100 percent of the replacement cost of the gas to be stored.[119]

Lastly, CGS notes that its proposal will require conforming modification to the CPIM. If its proposals are adopted, it will work with Cal Advocates to modify the CPIM as authorized in OP 32 of D.16-06-056.

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[118] Exh. PG&E-2 at 19-8 (citing Advice Letter 3884-G, Filed September 21, 2017).

[119] *Id.* at 19-8 to 19-9.

#### 5.7.1. Intervenors

CTA Parties assert that, in D.16-06-056, the Commission allowed CTAs to relinquish from PG&E the procurement of storage services for CTA customers. However, the Commission directed a transition period to avoid stranded cost issues. CTA Parties argue that, because PG&E proposes to reduce its storage assets within two years (compliance timeline for DOGGR May 19 Rule), stranded costs related to transitioning procurement to the CTAs should be minimal; therefore, the seven-year phase-out period should be eliminated.[120] Similarly, Commercial Energy argues that because PG&E' storage inventory, withdrawal, and injection capacity will decline under the NGSS, CTAs should not be required to comply with the seven-year phase-out requirements. Commercial Energy argues that this approach is similar to CGS group's request to be released from its obligation to allocate incremental ISP storage to CTAs.[121]

Commercial Energy and CTA Parties argue that a CTA should be permitted to procure its share of the firm core Storage Requirements for storage inventory, withdrawal and injection capacity from sources other than PG&E's or the ISPs' storage facilities.[122] Commercial Energy asserts that CTAs are currently permitted to satisfy their firm winter capacity requirements, set forth in PG&E Gas Schedule G-CT, using a variety of options that include delivery of gas from Citygate using a third party. Commercial Energy asserts that CTAs could meet 100 percent of their storage requirements with firm pipeline and firm Citygate

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[120] CTA Opening Brief at 11.

[121] Commercial Energy Opening Brief at 29-30.

[122] Commercial Energy Opening Brief at 47; CTA Parties Opening Brief at 17-19.

supply contracts. Thus, Commercial Energy asserts that CTAs should be able to use those resources to meet their firm core Storage Requirements.[123]

Commercial Energy argues that CTAs should not be allocated cost when PG&E elects to increase its interstate capacity in excess of 100 percent of the average daily load. Commercial Energy asserts that PG&E would need to procure additional interstate capacity to access gas at out-of-state basins for core customers during peak winter demand. However, Commercial Energy argues, bundled customers, not CTAs drive peak winter demand. Commercial Energy asserts that CTA load is relatively flat under normal and extreme weather conditions.[124]

Finally, Joint ISPs oppose PG&E's proposal to impose additional credit requirements requiring the ISPs to either (1) be rated as investment grade by Standard and Poor's or Moody's or (2) provide credit assurance that equals 100 percent of the replacement cost of the gas to be stored. Joint ISPs argue the Commission has already formulated credit requirements and that the amount of gas that a customer stores with an ISP has no direct correlation with an ISP's propensity to default on its contract; thus, PG&E has not demonstrated that the Commission's prior findings regarding ISP credit requirements should be revisited.[125]

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[123] Commercial Energy Opening Brief at 47.

[124] Commercial Energy Opening Brief at 48. CTA load ranges from 3,000 MDth/month to 4,000 MDth/month, while bundled core customers' load ranges from 10,000 to 33,000 MDth/month, or an increase of 133 percent versus 330 percent for CTA and bundled customers, respectively. *Id.*

[125] Joint ISPs Opening Brief at 22-24, 29-30 (citing D.06-07-010, petition for modification denied, D.08-07-009).

### 5.7.2. PG&E Response

PG&E disagrees with Commercial Energy's contention that CTAs should not be required to procure additional interstate capacity beyond the range set forth in D.15-10-050. PG&E argues that capacity would not only be used to address load spikes, as Commercial Energy asserts, but would also be used to offset the reduction in PG&E's storage capacity. Thus, PG&E argues, all core gas suppliers, not just CGS, will benefit from increasing the winter range maximum interstate capacity allocation.[126]

PG&E disagrees with Commercial Energy's contention that CTAs should be able to satisfy their core firm storage requirements with sources other than storage facilities. PG&E argues that Commercial Energy's proposal would allow CTAs to avoid procuring any firm storage capacity, which is a critical element of a reliable gas system. PG&E argues that Commercial Energy did not provide evidence to demonstrate that relieving CTAs of the obligation to procure storage capacity would be sufficient to ensure overall system reliability for core customers.[127]

PG&E also disagrees with Commercial Energy's contention that the commission should eliminate the seven-year phase-out of mandatory storage capacity and cost allocation for CTAs adopted in D.16-06-056. PG&E argues that, because it has unrecovered costs associated with Los Medanos and Pleasant Creek, it could have stranded costs, an issue that the seven-year phase-out was implemented to address. Moreover, PG&E argues that allocation of its storage to CTAs will not fall to zero until the next rate case; thus, until that

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[126] PG&E Opening Brief at 18-5.

[127] *Id.* at 18-2 and 18-3.

time, CTAs should be required to meet the cost-sharing obligations imposed on them for that storage capacity.[128]

#### 5.7.3. Discussion

We find that PG&E's changes to the Core Supply program, as proposed by its CGS group, are just and reasonable, except its proposals to remove the standby requirement, increase credit requirements for the Joint ISPs, and change the RFO process, as discussed below. Because the NGSS provides that PG&E will reduce its core gas storage inventory and withdrawal capacity, PG&E proposes to revise its portfolio for serving core customers to increase its intrastate pipeline allocations and available interstate pipeline allocations. We find that PG&E's has demonstrated that it considered relevant alternate factors in its proposal and that its proposal is reasonable.

As discussed in section 5.6.3, we find that the standby requirement continues to serves a critical purpose in the provision of public utility storage services. We also find that the RFO process continues to be a reliable method for implementing core firm storage contracts with ISPs. As discussed in section 5.6.3, we establish a similar contract approval process for core firm storage service contracts in Appendix I of this decision. This process allows PG&E's CGS group to execute bilateral contracts. As with the current RFO process, CTAs are not required to comply with the contract approval requirements provided in Appendix I. We find that because approximately 30 CTAs compete to provide gas service, the competitive nature of that market addresses the objectives of the contract approval process.

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[128] PG&E Reply Brief at 18-6.

With respect to the credit requirements for ISPs, we find the Commission's prior determinations on PG&E's proposals—that ISPs (1) should be rated as investment grade by Standard and Poor's or Moody's or (2) provide credit assurance that equals 100 percent of the replacement cost of the gas to be stored— should not be revisited at this time.[129] At this time, we find that the existing credit requirement process, which, among other things, requires an independent third-party to evaluate the financial strength of the ISP and, subsequently, assess the ISPs insurance obligations, will be scaled to meet the increased risk.

We find that PG&E's proposal that CTAs self-procure firm storage capacity to meet the Reliability Standard is reasonable. CTAs are currently self-procuring incremental storage capacity and do not object to extending their responsibility to include core firm storage. We decline to allow CTAs to meet their respective core firm storage requirements using resources other than storage facilities owned by PG&E or an ISP. Unlike firm pipeline capacity or firm Citygate contracts, storage capacity is reserved and available for immediate use. As discussed above, in determining its revised portfolio for providing core gas firm service, PG&E already considered a variety of supply mixes and has determined the amount of firm storage that is necessary.

We decline to eliminate the seven-year phase-out requirement set forth in D.16-06-056. In setting the seven-year transition period, the Commission reasoned that the pending legislation concerning the operations, maintenance and inspection of gas storage facilities would change the storage market.[130] As

[129] *See* D.06-07-010, petition for modification denied, D.08-07-009.

[130] D.16-06-056 at 374.

evidenced by the NGSS, the DOGGR May 19 rule did in fact significantly changed the storage market, as among other things, PG&E proposes to no longer provide price commodity services. Thus, we find that the findings in D.16-06-056 decision continue to be relevant.

We also decline to limit the interstate capacity allocation for the CTAs. We find as persuasive PG&E's contention that the cost of interstate capacity in excess of 100 percent of the average daily load should be allocated to all core customers because such capacity will be used, in part, to offset the reduction in PG&E's storage capacity, a function that will benefit all core gas suppliers.

### 5.8. Asset Holdings

#### 5.8.1. PG&E's Proposal

PG&E's storage asset family includes storage well components, including three underground gas storage fields: McDonald Island, Los Medanos, and Pleasant Creek.[131] McDonald Island, located in San Joaquin county and placed into service in 1959, is the largest of the three storage fields with a working capacity of approximately 82 Bcf, 81 injection and withdrawal wells, and 7 observation wells.[132]

Los Medanos, located in Contra Costa County and placed into service in 1980, has a working capacity of approximately 17 Bcf, 21 injection and withdrawal wells, and one observation well.[133] Pleasant Creek, placed into

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[131] Also, PG&E has a 25 percent ownership interest in the Gill Ranch storage field that is operated by Gill Ranch, LLC.

[132] These estimates reflect the status of PG&E's system at the time that its application was filed. Exh. PG&E-1 at 6-9 to 6-10.

[133] Exh. PG&E-1 at 6-10 and 6-11.

service in 1960, is in Yolo County and has a working capacity of approximately 2 Bcf and seven injection and withdrawal wells.[134]

To meet the Reliability Standard, PG&E proposes to source 857 MMcf/d of withdrawal capacity from its storage facilities.[135] Of that amount, PG&E proposes to supply 757 MMcf/d from McDonald Island because, it asserts, that location is the largest and most central of its three storage fields. To compensate for the 40 percent of withdrawal capacity that PG&E will lose in complying with the DOGGR May 19 Rule, PG&E proposes to build 11 new wells at McDonald Island. For the remaining 100 MMcf/d, PG&E proposes to convert its ownership shares at Gill Ranch to a utility asset, allowing PG&E to recover the capital and expense costs incurred to operate its share of the storage field.

As for Los Medanos and Pleasant Creek, PG&E states that it will attempt to sell them; however, it believes that "an acceptable sale is unlikely."[136] Thus, if PG&E is unable to sell the storage fields, PG&E proposes to begin decommissioning Los Medanos and Pleasant Creek starting on January 1, 2022. Before it decommissions the storage fields, PG&E proposes to convert them into production wells, starting on November 1, 2019, so that it can deplete the reservoirs before the storage fields are decommissioned or sold. PG&E asserts that converting the wells into production facilities will allow it to avoid bringing them into compliance with the DOGGR May 19 Rule. Specifically, PG&E asserts that for Los Medanos to comply with the DOGGR rule, among other things, it

[134] *Id.*

[135] PG&E's proposal for sourcing the remaining capacity is discussed in the section 4.9.3, Section III, Supply Standard and Existing Constraints.

[136] Exh. PG&E-1 at 11-14.

must retrofit 20 storage wells, costing at least $10 million in expenses and $51 million in capital expenditures over the instant rate case cycle.[137]

The scope of work to build the eleven new wells includes preparing the new well site, configuring a drill rig and related equipment, drilling the wells in accordance with certain design standards, conducting inspections and, lastly, connecting the wells. For this program, PG&E forecasts capital expenditures of $25 million in 2019 and $31 million in 2020.[138]

### 5.8.2. Intervenors

Some intervenors argue that PG&E's justification for restructuring its asset holdings is unsupported. Calpine, OSA, and Indicated Shippers assert that the cost estimates in PG&E's comparison scenario (Status Quo)[139] are overstated because they are based on a two-year timeline to comply with the DOGGR May 19 Rule.[140] Some intervenors argue that the Status Quo is insufficient to use as a comparison to the NGSS because it represents that PG&E would continue to participate in the gas storage market with its current storage capacity, rather than downsize its capacity to reflect the excess capacity holdings that PG&E asserts exist.[141]

Indicated Shippers and Calpine also argue that the NGSS is flawed because it excludes the costs that core customers will need to pay ISPs for storage services. Thus, Calpine and Indicated Shippers argue that the NGSS should have

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[137] PG&E Opening Brief at 11-31.

[138] PG&E Opening Brief at 6-11.

[139] *See supra* note 40.

[140] Calpine Opening Brief at 25-26; OSA Opening Brief at 8-10; Indicated Shippers Opening Brief at 36-43.

[141] Calpine Opening Brief at 29; Indicated Shippers Opening Brief at 36-43.

been compared to a different scenario. Specifically, Calpine argues that PG&E should have compared the NGSS to Scenario 3, which provides that PG&E would retain Los Medanos and Pleasant Creek and comply with the final DOGGR May 19 Rule, and that PG&E would neither convert Gill Ranch into a utility asset nor build new wells at McDonald Island. Scenario 3 would provide 864 MMcf/d of withdrawal capacity at a cost of $2.99 billion, the present value revenue requirement (PVRR) for 20 years.[142] Because the 20 year PVRR for the NGSS is $2.65 billion, Calpine argues that the difference between Scenario 3 and the NGSS is substantially less than the comparison between the NGSS and the Status Quo (*i.e.*, $366 million versus $1.5 billion).[143] Indicated Shippers argues that PG&E should adopt a modified version of Scenario 3, which includes the Gill Ranch capacity on an as-needed basis (Modified Scenario 3). Indicated Shippers asserts that the Modified Scenario 3 would provide 764 MMcf/d of withdrawal capacity for $333 million less than the NGSS, based on its comparison of the PVRR for each scenario over the three-year rate case period.[144]

Calpine and OSA argue that the Commission should reject PG&E's proposal and require it to provide a revised proposal in either the next rate case proceeding or a standalone application.[145] OSA argues that PG&E failed to "implement a management of change program to examine the safety and reliability issues associated with implementing the NGSS."[146]

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[142] Calpine Opening Brief at 30.

[143] *Id.* at 30.

[144] Indicated Shippers Opening Brief at 39.

[145] Calpine Opening Brief at 26; OSA Opening Brief at 7-8.

[146] OSA Opening Brief at 13.

Commercial Energy and TURN support PG&E's proposal to downsize its storage assets.[147] Cal Advocates neither supports nor opposes PG&E's proposal, except that it argues that the Commission should defer its decision on whether Los Medanos should be decommissioned, as discussed in a subsequent subsection.

Calpine and Indicated Shippers argue that the new wells are unreasonably expensive, costing at least $67 million in expenses from 2019-2022 and $56 million in capital.[148] Indicated Shippers argues that the new wells are an unnecessary expense as the 130 MMcf/d of capacity that they would provide could be sourced from ISPs.[149] Calpine argues that, because Reserve Capacity is unnecessary, if the Commission rejects that aspect of the NGSS, PG&E will not need the capacity that the new wells would provide.[150]

### 5.8.3. PG&E Response

PG&E admits that Scenario 3 would yield approximately the same delivery capacity as the NGSS. However, PG&E disagrees with intervenors who contend that it should implement Scenario 3 as doing so would cost at least $266 million more than the NGSS.[151] PG&E argues that this approach is risky given that the cost to implement the DOGGR May 19 Rule is uncertain.

PG&E disagrees with OSA's contention that PG&E's proposal will present reliability issues. PG&E argues that its proposed Reliability Standard is designed to deliver gas to core customers under multiple conditions, including an

[147] Commercial Energy Opening Brief at 21; TURN Opening Brief at 148.

[148] Calpine Opening Brief at 32-33; Indicated Shippers Opening Brief at 34.

[149] Indicated Shippers Opening Brief at 34-35.

[150] Calpine Opening Brief at 33.

[151] PG&E Opening Brief at 11-34 (citing Exh. IS-109 at 2, line 20 minus line 18).

Abnormal Peak Day (APD) one-in-90-year reliability event.[152] PG&E disagrees with OSA's contention that it could comply the wells at Los Medanos and Pleasant Creek with the DOGGR May 19 Rule without retrofitting the wells, among other requirements. PG&E argues that, unless it decommissions Los Medanos, it would be required to retrofit 15 wells, implement biannual inspections, and perform costly maintenance activities, such as replacing a compressor station.[153]

PG&E disagrees with intervenors who contend that the new wells are an unnecessary expense. PG&E asserts that it will be required to build new wells to make up for the capacity that it will lose when it implements the DOGGR May 19 Rule and closes its smaller storage fields.[154] Also, PG&E argues that the only storage facility that can deliver the required increment of gas into the Bay Area, downstream of pipeline constraints, is McDonald Island, not the ISPs' facilities.

#### 5.8.4. Discussion

We find that PG&E's proposal to restructure its asset holdings is just and reasonable, subject to conditions.[155] Of the 4,616 MMcf/d that the Reliability Standard requires, PG&E intends to supply 857 MMcf/d from its storage assets. Prior to the DOGGR May 19 Rule, PG&E's storage assets were able to supply 1,320 MMcf/d of withdrawal capacity.[156] However, PG&E will lose 40 percent of that capacity, bringing its total withdrawal capacity down to

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[152] PG&E Opening Brief at 11-23.

[153] *Id.* at 11-30.

[154] PG&E Opening Brief at 11-35.

[155] One condition is that PG&E must establish the contract negotiation process discussed in subsection 5.6 (Existing Storage Services).

[156] Exh. PG&E-1 at 11-15.

approximately 795 MMcf/d, which will be further reduced after PG&E decommissions or sells Los Medanos and Pleasant Creek. PG&E plans to decommission or sell those storage fields so that it can centralize its storage operations at McDonald Island, avoid bringing its smaller storage fields into compliance with the DOGGR May 19 Rule, and take advantage of less costly, more modern storage services.

For PG&E to make up the difference between its pre-DOGGR May 19 Rule storage capacity and the 875 MMcf/d of withdrawal capacity that it needs to source from its storage assets to meet the Reliability Standard, PG&E will need 230 MMcf/d of storage withdrawal capacity. Of that amount, PG&E plans to source the 130 MMcf/d of storage withdrawal capacity by build 11 new wells at McDonald Island, and it will source the remaining withdrawal capacity by using its share in Gill Ranch, a more modern, less expensive storage field. Both storage fields are unaffected by the pipeline constraints located north and south of the Bay Area demand.

Currently, PG&E uses its 25 percent share in Gill Ranch, which amounts to 100 MMcf/d, to support its storage operations on an as needed basis. However, pursuant to the NGSS, the 100 MMcf/d from Gill Ranch will be used to meet the Reliability Standard and, therefore, PG&E's request to convert Gill Ranch to a utility asset so that the associated revenue requirement is recovered from ratepayers is reasonable. To meet the remaining supply requirements of the Reliability Standard, aside from the pipeline capacity, Joint ISPs will supply 863 MMcf/d of withdrawal capacity. Pursuant to the MOU, ISPs represent they are willing and able to provide the withdrawal capacity that PG&E needs to meet the Reliability Standard (*i.e.*, 863 MMcf/d).

Some intervenors contend that PG&E should have compared the NGSS to a variation of Scenario 3, rather than the Status Quo. We find that these intervenors misunderstand the point of the comparison, which was for PG&E to demonstrate that maintaining enough withdrawal capacity to support its price commodity function is uneconomic given the impact that complying with the DOGGR May 19 Rule will have on PG&E's storage assets. Further, we find that PG&E did compare the NGSS to Scenario 3, and in doing so, demonstrated that the NGSS is the preferred approach as it is less expensive than Scenario 3 and allows PG&E to consolidate its storage operations. As such, we disagree with the intervenors who contend that the Commission should require PG&E to provide a revised proposal in the next rate case and note that doing so would be untimely as PG&E will begin complying with DOGGR May 19 Rule before the next rate case begins.

We also disagree with intervenors who contend that the Status Quo is overstated because it is based on a two-year timeline to comply with the DOGGR May 19 Rule. PG&E's estimated saving is based on the PVRR over a 20-year time period, not two years; thus, under either compliance timeline, the full costs to implement DOGGR May 19 Rule has been considered in PG&E's estimate.

We find that, because PG&E initiated and managed the process that resulted in the MOU, PG&E addressed OSA's concern about whether PG&E adequately planned for reliability issues. As discussed earlier, through the MOU, PG&E established a Reliability Standard, the purpose of which is to identify and resolve reliability issues.

With respect to the new storage wells, we find that PG&E's forecasts for building new wells is just and reasonable as PG&E provided enough evidence to support the estimated costs. Accordingly, we adopt PG&E's forecasted capital expenditures of $25 million in 2019 and $31 million in 2020 for the New Wells program.

##### 5.8.5. Decommission or Sale of the Los Medanos and Pleasant Creek Storage Fields

###### 5.8.5.1. PG&E's Proposal

Pursuant to the NGSS, PG&E proposes to close the Los Medanos and Pleasant Creek storage fields, which will require it to either sell or decommission storage well facilities (below-ground), and related compression and processing facilities (above-ground). To decommission the below-ground storage facilities, PG&E will remove tubing and other downhole equipment, install cement plugs inside the production casing to seal the wellbore, cut the well casing and cap it with a welded steel plate.[157] For above-ground facilities, which consist of compression and processing units, PG&E will remove piping and dehydration systems and demolish operations buildings, pump houses, and warehouses, among other structures.[158]

If PG&E is unable to sell the storage fields by January 1, 2022, it proposes to decommission 20 wells at Los Medanos during 2022 and 2023 and, for Pleasant Creek, three wells in 2022 and four in 2023. PG&E's forecast of the decommissioning costs for below-ground storage facilities and above-ground compression facilities is in Tables 2 and 3, respectively.

PG&E also intends to covert the wells at the Los Medanos and Pleasant Creek storage fields into production wells and, between

[157] Exh. PG&E-1 at 6-35.

[158] *Id.* at 7-78.

November 1, 2019 and December 31, 2021, produce the remaining customer gas from those wells.[159]

**Table 2-- Below-Ground Storage Decommissioning Costs**[160]
**($ Thousands of Nominal Dollars)**

| | | 2022 | | 2023 | |
|---|---|---|---|---|---|
| **Line No.** | **Field** | **No. Wells** | **Cost** | **No. Wells** | **Cost** |
| 1 | Los Medanos | 10 | $12,876 | 10 | $13,249 |
| 2 | Pleasant Creek | 3 | $ 3,863 | 4 | $ 5,300 |
| | Total | 13 | $16,739 | 14 | $18,549 |

**Table 3 - Above Ground Decommissioning Storage Costs**[161]
**($ Thousands of Nominal Dollars)**

| **Line No.** | **Storage Facility** | **2022** | **2023** |
|---|---|---|---|
| 1 | Los Medanos | $14,925 | $15,357 |
| 2 | Pleasant Creek | $ 6,425 | $ 6,611 |
| | Total | $21,350 | $21,968 |

#### 5.8.5.2. Intervenors' Response

Some intervenors argue that the Commission should either reject PG&E's proposal to decommission both storage fields or revise it to only allow PG&E to decommission Pleasant Creek. OSA argues that, rather than decommissioning Pleasant Creek and Los Medanos, PG&E should comply with the DOGGR May 19 Rule by plugging and abandoning its wells over the seven-year compliance term.[162]

Cal Advocates argues that the Commission should defer its decision to decommission Los Medanos until the next rate cycle for the following reasons:

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[159] *Id.* at 11-13.

[160] *Id.* at 6-35.

[161] PG&E Opening Brief at 7-71.

[162] OSA Opening Brief at 13.

> "(1) The immediate closure of the Los Medanos storage facility, along with the Pleasant Creek storage facility might have a larger negative impact on market and regulatory conditions in the natural gas business than PG&E anticipated.
>
> (2) Los Medanos is downstream of the Bay Area Pipeline constraint. Thus, it is needed to meet Bay Area demand on high peak demand days.
>
> (3) Deferring the decision on the sale or decommissioning of Los Medanos until the next GT&S rate case proceeding 'carries relatively little cost and removes substantial uncertainty.'
>
> (4) The sale of the smaller Pleasant Creek facility first provides learning opportunities and efficiencies that would improve the decision and implementation of a sale or decommissioning of Los Medanos, if the Commission so chooses."[163]

Further, Cal Advocates argues that "it is difficult to fully understand the impact of closing two of PG&E's storage facilities would have in a market and regulatory landscape that has become accustomed to having these facilities available."[164] However, Cal Advocates states that while it "does not anticipate any substantial market or regulatory changes at this time, deferring the decision to decommission Los Medanos carries relatively little cost . . . ."[165] With respect to reliability, Cal Advocates argues that PG&E "appears to believe that its proposal for reserve requirement, inventory management and a new reliability standard suffices to protect ratepayers from such impacts. This conclusion is speculative at best."[166]

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[163] Cal Advocates Opening Brief at 102.

[164] *Id.*

[165] Exh. ORA-11 at 5.

[166] Cal Advocates Opening Brief at 101.

Cal Advocates notes that, to keep Los Medanos open, PG&E may be required to replace the compressor station located at the field. However, Cal Advocates argues that this should not be a reason to reject its proposal as PG&E was already given an opportunity to recover the cost for a new compressor station in D.16-06-056.[167] If the Commission adopts its proposal to defer decommissioning Los Medanos, Cal Advocates recommends that the Commission require PG&E to file an Advice Letter stating how it plans to implement the DOGGR May 19 Rule at Los Medanos until a further decision on this matter is issued.[168]

Joint ISPs disagree with Cal Advocates' contention that decommissioning Los Medanos and Pleasant Creek will constrain the natural gas storage market.[169] Joint ISPs argue that, if the gas market in Northern California had been constrained, then the gas price at Citygate[170] would have been inconsistent with the trend of the NYMEX gas price. Moreover, Joint ISPs assert, the storage market in Northern California is overbuilt and for the last five years, these storage facilities have maintained a significant amount of available gas storage capacity, even during high demand events such as a polar vortex.[171] ISPs argue that the NGSS will not disrupt reliability as it will replace the combined capacity

[167] Cal Advocates Opening Brief at 103-104.

[168] *Id.* at 105.

[169] Joint ISP Opening Brief at 8.

[170] Citygate is the virtual trading point at which PG&E's backbone transmission system connect to its local transmission and distribution system. Available at: https://www.pge.com/pipeline/library/doing_business/citygate_diagram/index.page.

[171] Joint ISP Opening Brief at 8.

of Los Medanos and Pleasant creek, which is approximately 18 Bcf, with the combined capacity of the ISPs, which is 130 Bcf.[172]

Calpine, Commercial Energy, and Indicated Shippers assert that the Commission should require that PG&E either attempt to sell the storage fields or explore market interest during the current rate period before it decommissions the fields or attempts to recover decommissioning expenses.[173] Calpine asserts that, although PG&E contends that an acceptable sale is unlikely, PG&E's has not tested the market to determine which buyers are interested in purchasing the storage fields.[174] In fact, Commercial Energy asserts that it is interested in purchasing the storage fields.[175]

Commercial Energy argues that the Commission should reduce PG&E's cost estimates for decommissioning the storage fields. Commercial Energy asserts that PG&E's estimate is based on the cost to decommission wells that are providing storage services, rather than production service, which is less expensive. Commercial Energy explains that, if PG&E is able to extract all of the gas from the wells before it decommissions them, the down-hole pressure of each well will be significantly lower than if the wells were providing storage services. The lower pressure will require less mud and resources to plug and cap a storage well. Thus, Commercial Energy contends, PG&E's cost estimate of approximately $1.2 million per well is overstated and, instead, should be

[172] Exh. ISP-2 at 2.

[173] Calpine Opening Brief at 50-53; Commercial Energy Opening Brief at 4-5, 8-9; Indicated Shippers Opening Brief at 41-43.

[174] *Id.* at 52.

[175] Commercial Energy Opening Brief at 26.

approximately $100,000. Commercial Energy asserts that its estimate was provided by contractors located in Sacramento, California.

#### 5.8.5.3. PG&E's Response

PG&E disagrees with intervenors who contend that Los Medanos should not be decommissioned within the timeframe proposed in the NGSS. PG&E argues that it no longer needs the Los Medanos and Pleasant Creek storage fields; thus, "[k]keeping these aging, relatively small and costly facilities in service and making them compliant with the new DOGGR regulations would not be an efficient use of resources."[176] PG&E estimates that, to maintain storage services at Los Medanos during the rate case period, it would spend at least $10 million in expenses and $51 million in capital expenditures, which would exceed the amount that PG&E would spend through 2023 to implement the NGSS.[177]

PG&E reiterates that it cost estimate to decommission the storage fields are reasonable. PG&E argues that Commercial Energy offers no support for why the cost estimates for plugging a well would be less if the well was used for production services instead of storage services.[178]

#### 5.8.5.4. Discussion

We find that PG&E's request to close Los Medanos and Pleasant Creek is just and reasonable, subject to conditions. To meet its Reliability Standard, PG&E proposes a Supply Standard as part of the MOU, which is discussed in section 5.9. The Supply Standard provides that PG&E's storage fields

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[176] PG&E Reply Comment at 11-1.

[177] PG&E Opening Brief at 11-31. PG&E notes that these estimates excludes the estimated cost ($55 Million) to replace the compressor station at Los Medanos.

[178] PG&E Reply Brief at 6-2, 6-3.

(McDonald Island and Gill Ranch) will supply 857 MMscf/d of withdrawal capacity, 249 MMscf/d of injection capacity, and 11 Bcf of storage capacity. PG&E proposes to reduce its pre-NGSS Core Firm Services to 5 Bcf from 33.4 Bcf.[179] Thus, of the 11 Bcf of gas that PG&E's will store in its storage fields, 5 Bcf will supply PG&E's Core Firm Services. No party contends that PG&E will not be able to provide the capacity stated in the Supply Standard.

However, we find that PG&E's estimate of the amount of withdrawal and injection capacity that McDonald Island will provide after PG&E begins complying with the DOGGR May 19 Rule could be inaccurate given the uncertainty associated with the expansive scope of the retrofit and investigation activities required to comply with the DOGGR May 19 Rule. Unlike the Joint IPSs' storage fields, including Gill Ranch, PG&E's Los Medanos and McDonald Island storage fields are located within upstream and downstream pipeline constraints. Thus, if the actual loss in withdrawal and injection capacity at McDonald Island is substantially higher than 40 percent, PG&E's ability to provide reliable gas transmission service could be compromised.

Accordingly, to decommission Los Medanos, PG&E must file a Tier 2 Advice Letter on or after December 31, 2021, demonstrating that it has the requisite storage capacity to operate without the Los Medanos storage field. Until the PG&E's Tier 2 Advice Letter is approved, PG&E is not permitted to remove more than half of the working gas at Los Medanos or sell or begin decommissioning activities at Los Medanos.

In the Tier 2 Advice Letter, PG&E should also include an analysis of other supply constraints that could be exacerbated by closing Los Medanos.

[179] Exh. PG&E-1 at 10-10.

Specifically, PG&E must include an analysis of any constraints on upstream supply resources including, but not limited to, constraints related to the impact that regional shifts from coal generation to gas-fired generation may have on the core customers (through CTA or CGS) or wholesale customers' ability to procure gas.

If PG&E is precluded from decommissioning Los Medanos, PG&E must file another Tier 2 Advice Letter describing how it will remove the decommissioning costs from rates, update the depreciation parameters for Los Medanos, and refund ratepayers. Following the initial Tier 2 Advice Letter, on an annual basis, PG&E shall file a Tier 1 Advice Letter to inform the Energy Division on the status of the storage withdrawal capacity of its storage fields. We also require the ISPs to submit an annual report informing the Energy Division of the impact that complying with the DOGGR May 19 Rule is having on the ISPs' gas storage facilities, including withdrawal and injection capacity. The report shall be submitted during the third week of December each year until further notice, starting in December 2019.[180]

We are not persuaded by Cal Advocates' arguments that the Commission should indefinitely delay a decision on whether PG&E should decommission Los Medanos. First, we find that PG&E's closure of the storage wells at Los Medanos would not be "immediate" as PG&E proposes to decommission or sell the storage field starting in 2022, and to continue using some of the wells through 2023. Second, Cal Advocates asserts that it is "speculative at best" for PG&E to rely on its proposed Reliability Standard and new storage services to

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[180] The ISPs shall submit the reports to the Energy Division at edtariffunit@cpuc.ca.gov, unless otherwise directed by the Commission.

ensure that its system will be reliable without Los Medanos; however, Cal Advocates' Opening Brief offers no rebuttal to PG&E's proposals for those new services.[181] Thus, this argument is unsupported.

Cal Advocates argues that requiring PG&E to maintain Los Medanos will not be costly, yet the standard here is not whether an expense or capital expenditure will be expensive, which is relative. Rather, the standard is whether the costs are just and reasonable.[182] Here, PG&E asserts, and Cal Advocates does not dispute, PG&E would need to spend at least $10 million in expenses and $51 million in capital expenditures to maintain Los Medanos as a storage asset during the rate case period.[183] Thus, Cal Advocates has not demonstrated that such potential market and regulatory changes, which Cal Advocates admits will not be substantial, justifies or will offset the costs of maintaining Los Medanos as a storage asset.

Moreover, Cal Advocates does not describe the specific market and regulatory risks at issue or provide any related analysis of how removing approximately 18 Bcf of working gas, the capacity at Los Medanos, from the natural gas storage market will impact a particular aspect of the natural gas market or related regulations. With respect to the gas storage market, such a demonstration is necessary given that the Joint ISPs assert that the NGSS would

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[181] Cal Advocates Opening Brief at 100 (stating that Cal Advocates "does not oppose the adoption of a reliability standard if the NGSS or a portion there of is adopted); *id.* at (stating that Cal Advocates "does not oppose PG&E's proposal to establish new storage services, if the NGSS or a portion thereof is adopted).

[182] Section 451.

[183] PG&E Opening Brief at 11-31. PG&E notes that these estimates exclude the estimated cost ($55 Million) to replace the compressor station at Los Medanos.

replace the storage capacity at Los Medanos with their combined capacity of 130 Bcf.

As for the estimated cost to decommission each well, we are persuaded by Commercial Energy's contention that PG&E's estimates are unreasonable. We find that Commercial Energy's assertion that decommissioning a production well is less expensive than decommissioning a storage well is persuasive. We find that PG&E's rebuttal that – "CE offers no support in the record for this assertion, and it should be given no weight. Furthermore, it is incorrect . . . . "[184] —does not disprove Commercial Energy's assertion.

Considering that the wells at Los Medanos and Pleasant Creek will be in production status at the time that they would be decommissioned, Commercial Energy asserts that the cost to decommission each well should not exceed $200,000, which is $1 million less than PG&E's estimate. Based on the current record, it would be imprudent for PG&E's to spend an additional $1 million to decommission the wells. Accordingly, we direct PG&E to obtain quotes that focus on decommissioning production wells that will be depleted to the degree that PG&E estimates.

If PG&E is unable to identify a contractor that provides a quote for less than $1.2 million, PG&E must submit a Tier 2 Advice Letter for approval before it proceeds with decommissioning activities for both storage fields. PG&E may begin recovering its forecasted decommissioning costs in 2019; however, it is also required to establish a one-way balancing account to reflect any reduction to the its forecast. As noted in section 11 (Results of Operations), the amortization period is five years, rather than three years.

[184] PG&E Reply Brief at 6-2.

We agree with the intervenors' contentions that PG&E should make a good faith effort to sell the Los Medanos and Pleasant Creek storage fields before it begins decommissioning activities. Thus, on or before January 31, 2020, PG&E must submit a Tier 1 Advice Letter with its plan to receive offers from potential purchasers. As part of the Tier 2 Advice Letter that PG&E must file for authorization to decommission Los Medanos, PG&E must also include a summary offers from potential buyers and the reasons that PG&E declined to pursue each offer.

We also note that, if PG&E decides to sell the storage fields, then pursuant to Section 851, it must first file an application with the Commission to obtain permission to execute the transaction. The application must be subject to the outcome of the Tier 2 Advice Letter that PG&E must file to demonstrate that it has the requisite storage capacity to operate without the Los Medanos storage field, as discussed above.

Lastly, with respect to converting wells at Los Medanos and Pleasant Creek from storage to production service, we find that the PG&E should credit ratepayers for the amount of revenue received less any cushion gas purchased by PG&E's shareholders. Accordingly, we direct PG&E to implement a tracking account to record these transactions and to submit report of the recorded transactions to the Commission annually, starting on January 30, 2020. The disposition of the amounts recorded to the tracking account will be considered in the next GT&S rate case.

### 5.9. MOU

PG&E convened a public meeting on May 11, 2017, and subsequently several settlement discussions with a variety of stakeholders to discuss the issues causing PG&E to reconsider its gas storage services. On September 22, 2017, pursuant to Rule 12.6 of the Commission's Rules of Practice and procedure, PG&E noticed the draft MOU. On September 29, 2017, PG&E held a meeting with the joint parties to the MOU—PG&E's CGS; PG&E's Electric Fuels and Gas Operations groups; Central Valley Gas Storage, L.L.C.; Gill Ranch; Lodi Gas Storage, L.L.C.; TURN; Wild Goose Storage, LLC.

The MOU primarily sets forth the ISPs' responsibilities, rate design, and demand and supply components of the NGSS, some of which have been discussed above, such as the Reliability Standard. The remaining terms of the NGSS are decided below.

#### 5.9.1. Section I. Facilities Plan

The MOU provides that PG&E will (1) discontinue operations at Los Medanos and Pleasant Creek by December 31, 2021, (2) seek to sell Los Medanos and Pleasant Creek, but if a sale is not possible, (3) decommission the storage fields beginning no later than January 2, 2022. As discussed in subsection 5.8.5, PG&E is authorized to decommission Pleasant Creek, but the Commission's decision on decommissioning or selling Los Medanos is subject to the outcome of PG&E's Tier 2 Advice Letter filing.

#### 5.9.2. Section II. Costs

The MOU provides that the actual costs of operating PG&E's three storage facilities should be recorded and recovered through a two-way balancing account that is subject to a reasonableness review. Similarly, the MOU provides that if PG&E is required to retain its current storage capacity, it should record the additional capital and expense in a two-way balancing account. In section 6, we grant PG&E's request to establish a two-way balancing account for this purpose.

The MOU provides that PG&E should (1) depreciate the Los Medanos and Pleasant Creek facilities over their remaining useful life (*i.e.*, through 2021) and

(2) PG&E should recover its forecasted decommissioning costs for Los Medanos and Pleasant Creek from 2019 through 2021, subject to true up. In section 11 (Results of Operations), we determined that PG&E should extend the depreciation term and the period for which it may recover decommissioning costs to five years, starting in 2019. In section 5, we directed PG&E to perform further compliance activities to establish the decommissioning costs.

#### 5.9.3. Section III. Supply Standard and Existing Constraints

The MOU provides that (1) the Baja and Redwood paths have constraint and (2) PG&E shall use the supply components noted in Table 4 below to satisfy its proposed Reliability Standard from 2019 to 2021. The MOU provides the demand components that compose the Reliability Standard.

**Table 4—Supply Components for Reliability Standard[185]**
**(Million Standard Cubic Feet Per Day)**

| | |
|---|---|
| Redwood Path at Malin | 95% of 2,038 mmscf/d (1,936 mmscf/d) |
| Baja Path at Panoche | 95% of 1,010 mmscf/d (960 mmscf/d) |
| PG&E Gas Storage | 857 mmscf/d<br>(757 mmscf/d McDonald Island and 100 mmscf/d PG&E Gill Ranch) |
| Independent Storage Provider (ISP) Gas Storage | 863 mmscf/d |

We adopted the demand components of the Reliability Standard in sections 5.3 to 5.5. We find that the supply components are just and reasonable. PG&E's testimony demonstrates that the Baja and Redwood paths have constraints. We note that, because this decision adopts the 2022 attrition year, the Reliability Standard and related supply components will be effective through

[185] Exh. PG&E-1 at 11-Atch1-3.

2022, unless otherwise changed by the Commission. No party contested the constraints. Accordingly, we adopt the provision in this section of the MOU.

#### 5.9.4. Section IV. New and Modified Storage Services

The MOU provides that Tariff G-SFS should be eliminated, and PG&E agrees that it will not build any additional gas storage capacities for marketing purpose during the instant rate case period. The MOU provides that PG&E will buy and sell gas solely for operational purposes using the existing Balancing Charge Account and that PG&E shall report these transactions on a quarterly basis during the instant rate case period and on an annual basis during the subsequent rate case period.

The MOU provides that Tariff G-CFS, concerning CTAs, should be modified (1) to provide that the total core storage requirement will be shared with CTAs, TURN, and Cal Advocates on a confidential basis, (2) to provide that the minimum inventory in each CTA's storage account must be monitored by the Commission's Energy Division, and (3) to establish a residual core storage service, which will be based on storage capacity that remains after PG&E has satisfied the storage capacities for the Inventory Management and Reserve Capacity.

In addition, the MOU provides that the Tariff G-CFS should be modified to provide (1) Core Firm Service with the following capacities: 24 MMSCF/d for injection, 5 Bcf for inventory, and 307 MMSCF/d for withdrawal; (2) Reserve Capacity with the following capacities: 25 MMSCF/d for injection, 1 Bcf for inventory, and 250 MMSCF/d for withdrawal; and (3) Inventory Management with the following capacities: 200 MMSCF/d for injection, five Bcf for inventory, and 300 MMSCF/d for withdrawal.

The MOU provides that changes to Tariff G-CFS and the new storage services (Inventory Management and Reserve Capacity) will become effective beginning on the April 1 or May 1 that is at least 120 days after the issuance of the instant decision (Storage Services Effective Date). The MOU also provides that the rules for the Balancing service should not change for daily and monthly imbalances, but that after the Storage Service Effective Date, PG&E shall no longer use 75 MMSCF/d of injection and withdrawal capacity in the daily plan.

We find that the MOU provisions in MOU Section IV are just and reasonable, subject to conditions. As discussed in section 5.7 (Core Gas Supply), we agree with PG&E that CTAs, which currently serve about 18 percent of the core market in PG&E's service territory, must obtain gas storage so that the NGSS system reliability standard can be met and we concur that alternative resources, such as peaking contracts, are not acceptable substitutes for storage CTAs are responsible to obtain from ISPs.[186]

With respect to the provision that the Energy Division must monitor CTA compliance with PG&E's minimum inventory requirements, we appreciate PG&E's recognition of the importance to institute a process to ensure that CTAs can fulfil their gas storage obligations. While PG&E proposes that the Commission's Energy Division monitor the CTAs compliance with the gas storage requirements, we find that PG&E has the requisite resources and experience interacting with CTAs to effectively carry out this role.[187] However,

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[186] PG&E Opening Brief, at 18-9. The potential use of alternate resources by CTAs as a substitute for ISP gas storage under the D.06-06-056 step-down will be considered in the process adopted in Resolution G-3537.

[187] For example, PG&E administers the CTAs acquisition of pipeline capacity and the firm winter capacity requirement program under Gas Schedule G-CT.

as described below, the Energy Division will oversee PG&E's monitoring of the CTAs.

Accordingly, we direct PG&E to file a Tier 2 advice letter, no later than 30 days from today, with its proposal to monitor the amount of gas storage inventory CTAs procure and the level of gas they hold in storage that is necessary to support the NGSS reliability standard. The advice letter shall identify the gas storage information CTAs are to provide PG&E and when such information is to be furnished as well as include a fee or other mechanism intended to incentivize CTAs to comply with the gas storage requirements. For example, a possible mechanism could involve PG&E purchasing gas that would be billed to the CTA that does not have enough gas in storage at an index price plus a per decatherm fee similar to an OFO noncompliance charge.[188] The amount of the fee would be credited to the utility's bundled core customers through the Purchased Gas Account. Any conforming tariff modifications to implement the proposed monitoring program and noncompliance fees are to accompany the advice letter.

After the monitoring program has begun, PG&E shall submit a quarterly report to the Energy Division that lists the CTAs that PG&E has found to be out of compliance with the gas storage requirements, explains the nature of the noncompliance, and describes how compliance was achieved or if a CTA remains out of compliance.[189] If the Energy Division determines that a CTA has

[188] *See* PG&E Gas Rule 14.E.

[189] For reporting purposes, quarters correspond to the following months: Quarter 1 = January, February and March; Quarter 2 = April, May and June; Quarter 3 = July, August and September; Quarter 4 = October, November and December. Reports are to be submitted to the Energy Division no later than 5 business days after the end of a quarter to: edtariffunit@cpuc.ca.gov, unless otherwise directed by the Commission.

demonstrated a pattern of failing to meet their gas storage obligations, it may refer the CTA to the Consumer Protection and Enforcement Division (CPED) for appropriate enforcement action, including, but not limited to, the suspension and/or revocation of their CTA registration.[190] CTAs will have an opportunity to respond to PG&E's quarterly report and to any actions brought by CPED.

#### 5.9.5. Section V. Capacity and Cost Allocation

The MOU provides the allocation of storage capacity for the (1) McDonald Island and Gill Ranch Storage facilities and (2) storage services, as stated in the tables below.

**Table 5—Storage Capacity Allocation for PG&E Storage Facilities**[191]

| Facilities | Injection (mmscf/d) | Inventory (bcf) | Withdrawal (mmscf/d) |
|---|---|---|---|
| **McDonald Island** | 193 | 9 | 757 |
| **Gill Ranch** | 56 | 2 | 100 |
| **Total** | 249 | 11 | 857 |

**Table 6—Storage Capacity Allocation for Storage Services**[192]

| Storage Services | Injection (mmscf/d) | Inventory (bcf) | Withdrawal (mmscf/d) |
|---|---|---|---|
| **Core Service** | 24 | 5 | 307 |
| **Inventory Management** | 200 | 5 | 300 |
| **Reserve Capacity** | 25 | 1 | 250 |
| **Total** | 249 | 11 | 857 |

The MOU provides that the revenue requirement for each storage service should be based on the storage capacities allocated to each service. The percentage allocations are stated in Table 7. The MOU provides that the cost to

[190] *See* §§ 983.5(a), 983.5(b)(3) and 985(h) and D.18-02-002.

[191] Exh. PG&E-1 at 11-Atch1-5.

[192] *Id.* at 11-Atch1-5.

provide (1) core services will be recovered from all core customers, (2) Inventory Management will be recovered from customers through backbone rates, and (3) Reserve Capacity will be recovered from all customers through backbone rates. Noncore and other service revenue will be credited to all customers.

**Table 7—Cost Allocation Percentages for Storage Services**[193]

| **Storage Services** | Injection % | Inventory % | Withdrawal % | Total % |
|---|---|---|---|---|
| **Core Service** | 1.5 | 1.5 | 11.0 | 14.0 |
| **Inventory Management** | 21.7 | 1.5 | 32.6 | 55.8 |
| **Reserve Capacity** | 2.7 | 0.3 | 27.2 | 30.2 |
| **Total** | 26.0 | 3.3 | 70.8 | 100.0 |

We adopted the demand components in section 5.7 (Core Gas Supply). We find that the allocation of storage capacity and storage services, and the method for allocating costs are just and reasonable. As discussed in subsections 5.4 and 5.5, we decline to allow customers to opt-out of the new storage services (*i.e.*, Inventory Management and Reserve Capacity).

#### 5.9.6. Section VI. ISP Responsibilities

The MOU provides that firm core storage contracts must require ISPs to be responsible for the following items: (1) ISPs must engage with PG&E in daily operational calls between 6:30 a.m. and 7:00 a.m., 365 days per year;[194] (2) ISP must agree to make a reasonable, good-faith effort to implement PG&E's requests to adjust or shape injections and withdrawal profiles if such changes would avoid operations that may exceed the normal operating conditions on the system; (3) ISPs must carry and clear imbalances with PG&E on an Operating

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[193] Exh. PG&E-1 at 11-Atch1-5.

[194] During the call, ISPs must provide a detailed forecast per facility for injections and withdrawals for the current gas day and the next gas day.

Imbalance Account as requested by PG&E; (4) ISPs must provide live monitoring and control of all storage facilities 24 hours per day; (5) ISPs must help PG&E reduce the impact of lost injection or withdrawal on the transportation system; (6) ISPs must provide PG&E Gas Operations with notice of scheduled and nonscheduled facilities outages in terms of return-to-service date and time and capacity reduction; and (7) ISPs must report firm capacity to the Commission and PG&E Gas Operations on a confidential basis.

We find that these provisions are just and reasonable, subject to condition. Provisions 1-7, as stated in full in the MOU, are adopted. However, because the ISPs will provide 18 percent of the withdrawal capacity needed for PG&E to supply the Reliability Standard, we find PG&E's proposal to coordinate with the ISPs to clear imbalance issues requires monitoring. While pursuant to D16-06-056, CTAs currently obtain Core Firm Services from ISPs, now that PG&E will have less gas inventory on hand, PG&E will be more reliant on ISPs to help resolve system imbalances. Accordingly, we direct the Joint ISPs and PG&E to provide information on an annual basis that will allow the Commission's Energy Division to evaluate the coordination between the Joint ISPs' and PG&E to address system imbalance issues via a jointly filed an annual Tier 1 Advice Letter that includes the following: 1) identifies instances where ISP assistance was requested 2) describes circumstances why ISP assistance was needed, and 3) explains whether ISPs provided assistance and if not, why not.

#### 5.9.7. Section VII. General Provisions

The MOU provides that the General Provision section of the MOU will be effective upon the Commission's issuance of a final decision in the instant rate case; however, if the Commission rejects or modifies the MOU, the joint parties to the MOU reserve all rights set forth in Rule 12.4 of the Commission's Rules of

Practice and Procedure. Lastly, among other things, this section of the MOU also provides that the MOU may be amended or changed only by written agreement signed by the joint parties.

We find that this section is just and reasonable, subject to condition. We clarify that if the MOU is amended or changed, the revised MOU will not be effective until it is approved by the Commission through a Tier 2 Advice Letter filing.

## 6. Asset Family – Storage

### 6.1. Introduction

PG&E's storage asset family consists of ancillary well equipment, transmission pipes between storage wells and processing equipment, and storage well components, including three underground gas storage fields: McDonald Island, Los Medanos, and Pleasant Creek.[195] McDonald Island, located in San Joaquin county and placed into service in 1959, is the largest of the three storage fields with a working capacity of approximately 82 billion cubic feet (Bcf), 81 injection and withdrawal wells, and 7 observation wells.[196]

Los Medanos, located in Contra Costa County and placed into service in 1980, has a working capacity of approximately 17 Bcf, 21 injection and withdrawal wells, and one observation well.[197] Pleasant Creek, placed into service in 1960, is in Yolo County and has a working capacity of approximately 2 Bcf and seven injection and withdrawal wells.[198] As discussed in Section 5,

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[195] Also, PG&E has a 25 percent ownership interest in the Gill Ranch storage field that is operated by Gill Ranch, LLC.

[196] These estimates reflect the status of PG&E's system at the time that its application was filed. Exh. PG&E-1 at 6-9 to 6-10.

[197] Exh. PG&E-1 at 6-10 and 6-11.

[198] *Id.*

pursuant to PG&E's NGSS, PG&E proposes to decommission or sell the Los Medanos and Pleasant Creek storage fields beginning in January 2021.

PG&E uses six programs to manage its storage assets: (1) Reworks and Retrofits, (2) New Storage Wells,[199] (3) Integrity Inspection and Surveys, (4) Controls and Continuous Monitoring, (5) Repair and Replace Non-Storage Well Assets, and (6) Other Well-Related Projects. PG&E states that the programs are designed to incorporate risk mitigation and operational activities necessary to support gas system reliability, maintain well integrity, and balance the overall gas system. To identify and rank storage risks, PG&E states that it used its Integrated Planning Process, which assigns a risk score based on the likelihood and consequence of a system failure. PG&E states that it considered the nine threats identified in ASME B31.8S, and the risk management practices provided in the API RP 1171.[200]

PG&E states that the storage asset programs account for the activities necessary for PG&E to comply with state, federal, and local regulations. Specifically, PG&E states that, pursuant to SB 887, on May 19, 2018, DOGGR issued a draft regulation for storage fields, requiring PG&E to (1) ensure that a single point of failure does not pose an immediate threat, (2) continuously monitor its storage wells, and (3) conduct periodic integrity testing, including performing pressure tests every two years (DOGGR May 19 Rule). PG&E's

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[199] Because the cost estimated for the New Wells program is closely aligned with the Commission's decision on the NGSS, it is discussed in the NGSS section of this decision.

[200] PHMSA issued an Advisory Bulletin ADB-2016-02 in February 2016. The bulletin contains the DOGGR emergency regulation requirements and promotes the voluntary adoption of various programs, such as API's Recommended Practice 1171, Functionality Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs.

forecast of capital expenditures and expenses for these programs are summarized in Table 8 below.

To account for forecast uncertainties, PG&E requests a two-way balancing account, discussed below. Because it bases its forecasts on a seven-year compliance cycle, consistent with the final DOGGR May 19 Rule, PG&E withdrew its request for a post-test year expense adjustment for additional integrity assessments in 2021 and 2022 in its Opening Brief.[201]

**Table 8 – 2019 Expense Forecast for Storage Assets[202]**
**($ Thousands of Nominal Dollars)**

| | | | PG&E |
|---|---|---|---|
| Line No. | Description | MWC | Current Forecast |
| 1 | Well Integrity Management Plan (WELL) – Integrity Assessments (Surveys) | AH1 | $6,282 |
| 2 | WELL - Other | AH3 | $4,812 |
| 3 | WELL - Reworks Integrity Assessments | AH2 | - |
| | Total | | $11,074 |

**Table 9 – Updated Capital Forecast for Storage Assets[203]**
**($ Thousands of Nominal Dollars)**

| | | | PG&E | | |
|---|---|---|---|---|---|
| Line No. | Program | MWC | 2019 Forecast | 2020 Forecast | 2021 Forecast |
| 1 | WELL- Controls and Cont. Monitoring (MAT 3L5) | 3L | $14,524 | $1,791 | - |
| 2 | WELL – Repair and Replace (MAT 3L4) | 3L | 3,219 | 4,405 | 134 |
| 3 | WELL – Reworks and Retrofits (MAT 3L3) | 3L | 71,158 | 72,215 | 42,437 |
| 4 | Total | | $88,901 | $78,411 | |

[201] PG&E Opening Brief at 6-5.

[202] PG&E Opening Brief at 6-1.

[203] PG&E Opening Brief at 6-2.

#### 6.1.1. Reworks and Retrofits Program

The objective of the Reworks and Retrofits program is to replace or repair damaged equipment, replace the gravel pack in the well bore, and to implement changes necessary to comply with new and existing regulations. As noted earlier, PG&E must comply with the DOGGR May 19 Rule. Section 1726.5 of the rule requires PG&E to remediate wells that have a single-point-of-failure design. PG&E states that its wells are constructed with a single barrier of production casing and, therefore, must be retrofitted so that they have two barriers.

PG&E states that its estimate of the cost to retrofit the identified wells is based on the cost for site preparation, materials, labor, and rental equipment that will be used to install well cement, inner casing strings, and tubing and packing assemblies. Initially, the DOGGR May 19 Rule, required a two-year compliance timeline. On June 29, 2018, DOGGR granted PG&E's request to use a risk-based compliance schedule, which extended the compliance timeline to seven years. As such, in PG&E's direct testimony, it proposes capital and expense forecasts using a two-year compliance schedule, but, in its opening brief, PG&E provides revised forecasts based on a seven-year compliance schedule. PG&E argues that, because the revised forecast was calculated based on the final rule, that forecast is more reliable than the forecasts in its testimony. PG&E's revised forecast is above in Table 9.

TURN argues that PG&E should adopt forecasts that are consistent with the compliance timeline set forth in the final DOGGR rule. TURN argues that the "[i]gnoring the adoption of final regulations by a sister state agency such as DOGGR . . . would not result in a fully-informed judgment."

However, TURN contends that the Commission should reject the revised forecast that PG&E offered for the first time in its Opening Brief. TURN argues that adopting PG&E's revised forecast would deprive the parties of an opportunity to test the estimates through discovery, cross-examination, and responsive testimony. TURN argues the Commission should direct PG&E to adopt the seven-year compliance forecast that PG&E provided in its testimony (Alternate Forecast): $3.1 million in expenses for 2019 and $58.8 million in capital expenditures for 2019, $59.89 million for 2020, and $29.7 million for 2021.

We are persuaded by TURN's and PG&E's arguments that the expenses and capital expenditures for the Reworks and Retrofit program should be based on the compliance period designated in the final DOGGR May 19 Rule. As the parties note, the final DOGGR May 19 Rule allows PG&E to retrofit its wells over a seven-year timeline, rather than two years. The longer compliance timeframe will allow PG&E to retrofit its wells using a slower pace; therefore, the cost of PG&E's expenses and capital expenditures for the rate period will be lower than the original forecast as it was based on a two-year compliance period. Accordingly, allowing PG&E to use forecast estimates that are consistent with a seven-year compliance term will be both consistent with the final DOGGR May 19 Rule and more reflective of the expenses and capital expenditures that PG&E will ultimately need to recovery from ratepayers.

With respect to the forecast that we should adopt, PG&E asserts that that the Commission should approve estimates that PG&E derived from Exhibit IS-109, while TURN asserts that PG&E should adopt the Alternate Forecast. As noted earlier, the standard of proof that PG&E must meet is that of a preponderance of evidence, which is defined in terms of "probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[204] Said another way, PG&E must present more evidence that supports the requested result than would support an alternative outcome.

Here, the evidence presented in the Alternate Forecast was provided in PG&E's testimony and tested by the parties while the data in Exhibit IS-109 and the forecast derived from it was not provided as direct evidence until PG&E submitted its Opening Brief. While Exhibit IS-109, which is PG&E's response to Indicated Shipper's data request, was moved into evidence, the parties nevertheless did not have notice that PG&E would use the data from this exhibit to calculate the forecast that PG&E would seek to include in its rate. Accordingly, without the requisite notice, the data in Exhibit IS-109, while relevant in that it confirms that the seven-year compliance would result in lower costs, was not directly relevant to PG&E's case in chief: the costs that the PG&E seeks to have included in the storage revenue requirement. Consistent with the perceived relevance of data in Exhibit IS-109, during the hearing, the parties did not test the veracity of the data in the exhibit.

In contrast, in its testimony, PG&E specifically asserted that, if DOGGR accepted PG&E's request for a seven-year compliance period, it "estimates that the slower pace of work would reduce the 2019 expense forecast by $2.9 million (MAT AH1) and the 2019 capital forecast by $101.5 million (MAT 3L3)." TURN, in its testimony, evaluated PG&E's statement and, after the DOGGR May 19 Rule was finalized, argued that PG&E should adopt the reduced estimates. Before briefing, PG&E rebutted TURN's testimony, which at the time opposed PG&E use of forecasts that were based on the two-year compliance timeline. TURN had

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[204] *Supra* at 4.

an opportunity to respond to PG&E's rebuttal, further developing the record with the facts necessary to evaluate each proposal. Accordingly, we find that the estimated expenses and capital expenditures provided in PG&E's testimony, as reviewed by the parties, are more credible than the forecast that PG&E derived from the data in Exhibit IS-109.

We also find unconvincing PG&E's argument that, because the data in Exhibit IS-109 was compiled after the DOGGR May 19 Rule had been finalized, the revised forecast in its Opining Brief is more reliable than the Alternate Forecast. PG&E did not state the aspects of the final rule that would require it to divert from its estimate in the Alternate Forecast. Furthermore, TURN asserts that it has not been able to reconcile the data in Exhibit IS-109 to PG&E's revised forecast. Accordingly, for the forgoing reasons, we find that that Alternate Forecast that PG&E set forth in its testimony should be adopted.

In summary, the expense forecast for Maintenance Activity Type (MAT) AH1 is $3.1 million, and the capital expenditures forecasts for MAT 3L3 is $58.8 million for 2019, $59.9 million for 2020, $29.8 million for 2021, and $30.5 million for 2022. We direct PG&E file a revised retrofit schedule based on the seven-year compliance timeline.

### 6.2. Controls and Continuous Monitoring

PG&E states that Section 1726.7 of the final DOGGR May 19 Rule requires it to monitor its gas storage operations continuously. To fulfill this requirement, PG&E proposes to install, by the end of 2019, equipment at McDonald Island that will continuously monitor pressure at certain zones in the well and measure the injection flow stream in the wells. In addition, PG&E states that, by the end of 2020, it will install injection management equipment to control gas volumes in the wells at McDonald Island and provide monthly injection information to DOGGR.

Lastly, PG&E will replace obsolete monitoring equipment with new equipment that will shut down wells when the pressure in the tubing is low, when flood conditions are detected, and when a high level of hazardous waste is detected in the waste condensate tank.

PG&E used vendor quotes and engineering estimates to forecast the capital expenditures for the Controls and Continuous Monitoring program. PG&E's forecast is above in Table 9.

We find that PG&E's forecast for the controls and continuous monitoring projects is just and reasonable. The forecast provides funding for capital projects to install annual monitoring and management equipment by the end of 2019 and injection measurement equipment by the end of 2020. No party protested the forecast. Accordingly, we adopt PG&E's capital expenditure forecast for Controls and Continuous Monitoring.

### 6.3. Repair and Replace

PG&E's Repair and Replace program manages its efforts to repair and replace above ground storage equipment, such as pipelines and valves, at the McDonald Island Storage Field.[205] PG&E proposes two storage-related pipeline replacement projects. PG&E states that, because the Whisky Slough Station has pipelines that are corroded and too small to use with inspection tools without significant retrofitting, it will replace them by the end of 2018. PG&E states that the Turner Cut Station has similar pipeline components, so it plans to replace them by the end of 2020. The scope of the replacement project includes

[205] PG&E Opening Brief at 6-4.

developing a master transmission pipeline design, replacing the piping that runs from the station platform to the storage wellhead.

For storage-related valves, PG&E states that it plans to inspect and, if necessary, repair or replace Uphole Safety Valves, well valves, and sand inspection valves. PG&E forecasts the replacement costs using the recorded costs for similar work in 2016 plus an escalation factor. PG&E's forecast is shown in Table 9 above.

We find that PG&E's forecast for storage-related repair and replace projects is just and reasonable as it provided enough evidence to support each cost component. We note that the capital expenditures forecasted for 2018 are 100 percent higher than 2017; however, we attribute the increase to PG&E's plan to finish replacing the corroded pipelines at the Whisky Slough Station at the same time that it starts replacing pipelines at the Turner Cut Station. No party protested the forecast. Accordingly, we adopt PG&E's capital expenditure forecast the Repair and Replacement program.

### 6.4. Other Well-Related Projects Program

PG&E plans to conduct hydrostatic testing in pipelines at the McDonald Island storage field and provide engineering support for expense projects, such as integrity management and gas storage emergency site plans and support. PG&E's cost estimate for the hydrostatic testing is shown in workpapers, and its estimates for the engineering support is based on historical spending for work performed on similar projects, adjusted to include escalated costs. For 2019, PG&E forecasts $4.8 million in expenses for the Other Well-Related Projects program.

We find that PG&E's forecast for the Other Well-related Projects program is just and reasonable as it provided enough evidence to support each cost component. No party protested the forecast. Accordingly, we adopt PG&E's 2019 expense forecast for the Other Well-Related Projects program.

### 6.5. Integrity Inspection and Surveys

PG&E states that pursuant to Title 14, section 1724.10(j) of California Code of Regulations, it must survey its wells using noise and temperature logs to perform integrity tests, which confirm whether injected fluid is confined to the approved zones within the well. PG&E states that the final DOGGR May 19 Rule also requires it to annually perform Gamma Ray Neutron surveys, which determine the likelihood that gas exists outside of the well barriers. In addition, the final rule requires PG&E to perform biennial inspections of the well barriers to identify internal and external metal loss.

To meet these requirements, for each year in the rate case period, PG&E states that it will perform annual compliance surveys on all wells and barrier inspections on half of the storage wells. PG&E based the forecasted cost for the surveys and inspections on contractor estimates and includes costs for material, labor, and equipment rental for each project.

PG&E's estimated forecasted 2019 expense for the Integrity Inspection and Surveys program (MAT AH1) is $6.3 million.

As discussed above in Section 6.1, we find that PG&E's expense forecast for this program should be reduced to $3.1 million.

### 6.6. Two-Way Balancing Account

#### 6.6.1. PG&E's Proposal

PG&E requests a two-way Gas Storage Balancing Account to manage the forecast discrepancies that it anticipates will result when certain foreseeable events materialize. PG&E states that, because new regulations governing its gas storage assets were in draft or interim form at the time that it filed the instant application, the pace of work and related expenditures for programs responsible for Major Work Categories (MWC) 3L and AH could vary after the final regulations are adopted.

If the Commission does not adopt the NGSS, PG&E asserts that it would seek to add additional costs that are not currently forecasted in MWCs 3L and AH. PG&E asserts that the unit cost for implementing compliance activities could be higher than forecasted if the availability of contractors is constrained.

PG&E states that the Gas Storage Balancing Account would exclude expenditures associated with compression and processing, measurement and control, and programs that are within the transmission pipeline asset family but support natural gas storage.

TURN supports PG&E's proposal for a two-way balancing account, provided that the account is subject to a reasonableness review in a subsequent application. TURN argues that given the "uncertainty surrounding the implementation of the final DOGGR regulation," among other things, a two-way balancing account is appropriate. TURN asserts, a two-way balancing account would protect customers and PG&E if actual storage costs differ from the forecast.

We find that PG&E's request for a two-way balancing account for gas storage expenditures is reasonable. We agree with TURN's assessment of the uncertainty of costs associated with PG&E's implementation of the DOGGR regulations. While the regulations have been finalized, eliminating the single-point-of-failure design for over 80 injection and withdrawal wells could be a significant undertaking given the scope and nature of the rework required.

We also agree with TURN's recommendation that the Gas Storage Balancing Account should be subject to a reasonableness review. Accordingly, PG&E shall file a Tier 2 Advice Letter to establish a two-way balancing account to track the difference between the expense and capital expenditure amounts adopted in this decision and the portion of actual costs that PG&E incurs for these programs over the 2019 GT&S rate cycle. In the next rate case, PG&E shall submit an analysis comparing the total recorded costs with the authorized amount, and the Commission will determine whether the transactions in the balancing account are reasonable.

## 7. Asset Family – Facilities

The Facilities Asset Family consists of PG&E's programs for Compression and Processing (C&P) stations and Measurement and Control (M&C) stations. PG&E asserts that the C&P and M&C assets are designed for specific flow rates and pressures and are used to provide continuous, safe and reliable supply during normal and high gas demand periods.[206]

The C&P assets include gas compression equipment and related components, such as filter separators, pumps, motor control centers, gas coolers, station piping, station values, electric generating units, and Supervisory Control and Data Acquisition (SCADA) equipment. PG&E's C&P compressor equipment moves gas on PG&E gas transmission system from receipt points to customer delivery locations.[207] PG&E maintains eight compressor stations on its backbone transmission system, five of which are on Lines 400 and 401 (northern pipelines) and three are on Lines 300 A and B (southern pipelines).[208] PG&E maintains storage compressor units at each of its storage fields to inject gas into the storage

[206] Exh. PG&E-1 at 7-9.

[207] *Id.* at 7-8.

[208] *Id.*at 7-9.

reservoirs at high pressures. PG&E states that it placed the majority of its compressor assets in service between the 1950s and 1970s.

The M&C assets include (1) gas terminals, which route gas from PG&E's backbone transmission lines to its local transmission lines, (2) gas quality equipment, which monitors the quality of gas entering PG&E's transmission system, (3) large-volume-customer regulation and meter stations, which deliver a large volume of gas (*e.g.*, 40,000 standard cubic feet per hour or more) and measure the gas flow at customer connection points, (4) automated valves, such as automated and automatic shutoff valves, and (5) transmission stations, which regulate and monitor gas pressure, flows, and quality of the gas.[209] PG&E maintains approximately 556 gas transmission stations throughout its service territory.

PG&E assesses the condition of its M&C assets based on an assessment of the asset's age, obsolescence, physical condition, functional performance, maintenance history, and input from subject matter experts.[210] For its C&P assets, PG&E states that it developed a compressor inventory plan to provide a long-term forecast of the timing and duration of compressor asset replacements and costs.[211]

C&P has the following programs: (1) compressor replacements, (2) compressor unit control replacements, (3) upgrade station controls, (4) emergency shut down (ESD) system upgrades, (5) routine capital and expense, and (6) gas transmission electrical upgrades (Hinkley and Topock

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[209] *Id.* at 7-8.

[210] *Id.* at 7-20.

[211] *Id.* at 7-19.

compressor stations). C&P and M&C share the Facilities Integrity Management Program (FIMP), which PG&E uses for risk management.[212]

M&C has the following programs: (1) station rebuilds, (2) transmission terminal upgrades, (3) Becker System upgrades, (4) routine capital and expense, (5) station over-pressure protection enhancements, (6) gas quality assessment (7) critical documents (8) station assessments, and (9) physical security.

PG&E's estimate of 2019 expenses for the Facilities Asset Family is $33 million. The itemized expense forecast for each program is below in Table 10. PG&E's capital expenditures forecast for the Facilities Asset Family is below in Table 11.

**Table 10 – 2019 Expense Forecast for Facilities Assets[213]**
**($ Thousands of Nominal Dollars)**

| Line No. | Program | MAT | PG&E Filed Forecast | PG&E Errata | PG&E Current Forecast |
|---|---|---|---|---|---|
| 1 | Routine Expense Compression and Processing (C&P) | JTY | $11,259 | - | $11,259 |
| 2 | Routine Expense Measurement and Control (M&C) | 34A, JTW | 6,451 | - | 6,451 |
| 3 | Becker System Upgrades | JTY | - | - | - |
| 4 | M&C Gas Quality Assessment | 34A, JT8 | 1,040 | - | 1,040 |
| 5 | M&C Station Over Pressure Protection (OPP) Enhancements Expense | 34A, JTW | 1,561 | - | 1,561 |
| 6 | Facility Integrity Management Program (FIMP Risk Management | 34A, JTI | 2,752 | 57 | 2,809 |
| 7 | Critical Documents | 34A, LU1 | 3,143 | - | 3,143 |
| 8 | Engineering Critical Assessment (ECA) Phase 1 Expense | 34A, LV1 | 4,612 | 109 | 4,720 |
| 9 | ECA Phase 2 Expense | 34A, LV2 | 1,835 | - | 1,835 |
| 10 | Station Strength Testing Expense | 34A, JTV | 1,014 | - | 1,014 |
| 11 | Total Expense | | $33,667 | $166 | $33,833 |

[212] *Id.* at 7-1 and 7-23.

[213] PG&E Opening Brief at 7-2.

**Table 11 – Capital Forecast for Facilities Assets[214]**
**($ Thousands of Nominal Dollars)**

| Line No. | Program | MAT | PG&E 2019 Forecast | PG&E 2020 Forecast | PG&E 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Routine Capital (C&P) | 76N | $38,535 | $39,745 | $40,914 |
| 2 | Emergency Shut Down (ESD) Systems | 76F | 3,843 | 3,857 | 3,850 |
| 3 | Install Active Fire Suppression Systems | 76O | - | - | - |
| 4 | GT Electrical Upgrade- Hinkley, Topock Compression Stations | 76P | 4,270 | 4,285 | 4,277 |
| 5 | Compressor Unit Control Replacement | 76R | 3,268 | 3,280 | 3,273 |
| 6 | Upgrade Station Controls | 76T | 2,014 | 2,022 | 2,018 |
| 7 | Compressor Stations | 76H | - | - | - |
| 8 | Station Other | 76I | - | - | - |
| 9 | Compressor Replacement | 76X | 21,530 | 20,640 | 22,074 |
| 10 | Compressor Retrofit Projects | 76Y | - | - | - |
| 11 | Routine Capital M&C | 44A, 75C | 18,192 | 18,763 | 19,315 |
| 12 | Becker System Upgrades | 766 | 325 | - | - |
| 13 | Replace Obsolete Bristol Controllers | 761 | - | - | - |
| 14 | Perform Simple Station Rebuilds | 44A, 763 | 6,223 | 6,245 | 6,234 |
| 15 | Perform Complex Station Rebuilds | 44A, 764 | 32,311 | 32,431 | 32,368 |
| 16 | Perform Transmission Terminal Upgrades | 765 | 7,436 | 7,544 | 7,622 |
| 17 | Station OPP Enhancements Capital | 44A, 76G | 6,139 | 6,162 | 6,100 |
| 18 | ECA Phase 1 Capital | 76Q | - | - | - |
| 19 | ECA Phase 2 Capital | 44A, 76S | 287 | 575 | 595 |
| 20 | Station Strength Testing Capital | 44A, 76V | 102 | 185 | 256 |
| 21 | Physical Security Capital | 76Z | 9,392 | 9,427 | 9,409 |
| 22 | Total Expenditures | | $153,868 | $155,162 | $158,355 |

### 7.1. C&P Compressor Replacements

PG&E maintains 41 compressor units at stations located on its gas transmission system and underground storage facilities.[215] PG&E asserts that 65 percent of the units are over 40 years old. PG&E states that it has difficulty obtaining parts and service support for some of the older assets that are no

214 PG&E Opening Brief at 7-3.

215 PG&E Opening Brief at 7-22.

longer supported by the original manufacturer.[216] Accordingly, PG&E uses a Compressor Replacement Program to plan and manage the replacement of the older compression units.

PG&E plans to retire and replace obsolete compressor units, related equipment, and to install a compressor building, security upgrades and ancillary equipment. Based on cost estimates developed by an engineering and construction firm, PG&E's capital expenditure forecast for this program is in Table 12.

**Table 12 – Compressor Replacement Program Summary[217]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Burney K2 Replacement | 76X | - | - | - |
| 2 | McDonald Island K7-K9 Replacement | 76X | $21,530 | $4,052 | - |
| 3 | Tionesta K1 Replacement | 76X | - | 16,588 | $22,074 |
| 4 | Total Compressor Replacement | | $21,530 | $20,540 | $22,074 |

TURN argues that PG&E's forecast for compressor replacements should be reduced by $16.1 million, the cost overrun for the Burney Station Upgrade that the Commission authorized in D.16-06-056. TURN asserts that D.16-06-056 authorized PG&E to recover $54.1 million for the Burney compressor upgrade project and $57.032 million for the Los Medanos compressor station upgrade project. TURN assert that PG&E will spend $70.2 million, between 2015-2019, for the Burney Station Upgrade project and nothing for the Los Medanos project, as it was cancelled.[218] TURN argues that even though PG&E covered the cost overruns by diverting funds authorized for the Los Medanos project, PG&E is

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[216] Exh. PG&E 1 at 7-18.

[217] PG&E Opening Brief at 7-10.

[218] TURN Opening Brief at 94-95.

nevertheless required to demonstrate that the cost overruns are reasonable.[219] TURN argues that PG&E has not justified the reasonableness of the cost overruns for the Burney Station Upgrade project and, therefore, the Commission should direct PG&E to remove the cost overruns from its test year 2019 rate base.[220]

PG&E asserts that the cost overruns for the Burney Station Upgrade project were due to it increasing the scope of the project to include activities such as constructing a new control building.[221] In addition, PG&E states that the cost overruns include $4.95 million that PG&E spent to implement physical security upgrades, which is managed under a different program (Physical Security). PG&E states that it incorporates the physical security upgrades into the compressor station upgrade project because "it made[d] more sense to perform the upgrade as part of the project as opposed to as a separate construction activity."[222] Accordingly, PG&E argues that it has demonstrated that the cost overruns were reasonably incurred and, therefore, the full cost for the Burney System Upgrade project should be included in rate base.[223]

We find that PG&E's forecast for the C&P Compressor Replacement program is just and reasonable. We disagree with TURN's contention that the Commission should require PG&E to remove from rate base the cost overruns for the Burney Compressor station upgrade project. The Burney Station Upgrade project is a part of the Compressor Replacement program, which had enough funding to cover the overruns associated with the increased scope of the Burney

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[219] TURN Opening Brief at 94-95.

[220] TURN Opening Brief at 94.

[221] PG&E Opening Brief at 7-24.

[222] PG&E Opening Brief at 7-24 and 7-25.

[223] PG&E Opening Brief at 7-23.

project. We agree with TURN that PG&E has the burden to demonstrate that the cost overruns were reasonable but find that PG&E met its burden when it demonstrated that the broadened scope of the project required it to incur additional costs.

However, we find that the cost for the physical upgrades should have been attributed to the Physical Security program instead of the Compressor Replacement program. While, from a construction perspective, as PG&E asserts, it may have been more efficient for it to combine the two projects, we find that, from a regulatory accounting perspective, the funding for these programs should be maintained separately. Accordingly, PG&E should account for physical security upgrades in the Physical Security Program.

### 7.2. C&P Routine Capital and Expense

The C&P Routine Capital and Expense program accounts for capital projects and expenses that do not qualify for the other C&P programs. The program manages several expense activities such as maintenance work and equipment leases,[224] and capital projects such as upgrading turbines at compressor stations and replacing valves.[225]

To determine the scope of work for this program, PG&E used information that it gathered from conducting a "benchmark survey" of its C&P stations.[226] PG&E states that it forecasted the capital expenditures and expenses for this program using an adjusted three-year historical cost average from 2014-2016.[227] PG&E's capital expenditure forecast for this program is in Table 11 above.

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224 PG&E Opening Brief at 7-12.

225 Exh. PGE-1 at 7-30 to 7-31; *see also* PG&E Opening Brief at 7-5.

226 Exh. PG&E-1 at 7-30.

227 PG&E adjusted for a large one-time project and projects related to new regulations.

### 7.2.1. Intervenors

Cal Advocates argues that PG&E's expense forecast for the C&P Capital and Expense program should be based on a five-year historical average from 2012-2016.[228]

TURN argues that PG&E's forecasted expense for 2019 is overstated. TURN asserts that PG&E has not justified why its 2019 forecasted expense should be $3.4 million higher than the recorded amount for 2016. In addition, TURN argues that PG&E's forecast for this program has been consistently inaccurate. For example, TURN asserts that, for 2017, PG&E estimated $13.9 million in expenses, but recorded only $9.2 million.[229] TURN recommends that the Commission direct PG&E to use the expense amount that it recorded for 2017. TURN argues that its approach is consistent with Commission guidelines recommending that the amount of expenses in the last recorded year should be used to estimate future expenses when costs trend in one direction over three or more years.[230] TURN asserts that for the last three years, the expense for this program has been trending upward.

Accordingly, TURN argues that the Commission should direct PG&E to make a $2.104 million downward adjustment to its 2019 expense forecast.[231]

### 7.2.2. PG&E Response

PG&E disagrees with Cal Advocates' proposal because it does not account for the California Air Resource Board's (CARB) new regulations, which went into effect in 2017. Similarly, PG&E disagrees with TURN's proposal because the

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[228] Cal Advocates Opening Brief at 54-55.

[229] TURN Opening Brief at 90.

[230] *Id.* at 89-91.

[231] *Id.* at 89-90.

projects that will support PG&E's compliance with the new CARB rules were not recorded in 2017. Accordingly, PG&E argues that its expense forecast of $11.3 million for 2019 should be adopted.

#### 7.2.3. Discussion

We find that PG&E's forecasted capital expenditures for the C&P Routine Capital and Expense program is just and reasonable. No party opposed the capital expenditure forecast.

For the expense forecast, we agree with TURN's proposal. PG&E states that the 2017 recorded amount does not include the cost that it will incur to comply with the new CARB regulations, yet it failed specify the tasks and associated cost for complying with the new regulations. Thus, for 2019, we direct PG&E to use the 2017 recorded amount for this program (*i.e.*, $9.155 million) and to establish a memorandum account to track expenditures exceeding that amount.

### 7.3. M&C Station Rebuilds

PG&E uses the M&C Station Rebuilds program to manage projects that rebuild above and below ground stations, replace aging and obsolete equipment, replace valves and piping, and implement maintenance activities.[232]

PG&E estimates that that it will upgrade five stations per year, three complex stations and two simple stations. Generally, the simple stations do not have Programmable Logic Circuits (PLC). PG&E states the cost estimates for the projects were developed by an engineering and construction firm with experience in constructing gas transmission facilities. PG&E's capital expenditure forecast for this program is in Table 11 above.

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[232] PG&E Opening Brief at 7-10.

#### 7.3.1. Intervenors

TURN argues that PG&E's recorded expenses for this program exceed the amount that the Commission authorized in the 2015 GT&S rate case and, therefore, should be disallowed. For simple stations, TURN asserts that, in D.16-06-056, the Commission authorized PG&E to rebuild 30 station for $81.6 million which is approximately $2.78 million per simple station. By 2018, however, TURN asserts that PG&E had rebuilt only three simple stations and spent $20.8 million, for an average project cost of $6.9 million.[233] For complex stations, TURN asserts that PG&E was authorized to rebuild eight stations by 2018 for a capital cost of $34 million, but that PG&E rebuilt nine complex stations for a total cost of $156.9 million, for an average of $17 million per station. TURN argues that PG&E has not adequately explained the reason it incurred costs in excess of the amount that it was authorized to spend for each project. Accordingly, TURN argues that the Commission should disallow approximately $102 million and the respective amount for depreciation expense.[234]

Cal Advocates requests that the Commission direct PG&E to maintain a one-way balancing account for the M&C Station Rebuilds program. Cal Advocates argues that there is a reasonable likelihood that PG&E will not be able to construct five stations per year. Cal Advocates argues that for the last rate case, PG&E asserted that it would rebuild 34 stations, yet it was able to rebuild only four stations over the entire rate case period. In addition, Cal Advocates asserts that PG&E will need land permits for all of the stations,

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[233] TURN Opening Brief at 97.

[234] *Id.* at 99, Tables 30 and 31.

and it is uncertain that PG&E will be able to obtain five land permits per year without delay.[235]

#### 7.3.2. PG&E Response

PG&E disagrees with Cal Advocates' recommendation that PG&E setup a one-way balancing account for the M&C Station Rebuilds program. PG&E argues that, during the prior rate case period, it reprioritized this program to focus on rebuilding complex stations. PG&E asserts that it reprioritized the projects based on station-specific assessments and field verifications that it performed after its 2015-2018 rate case application had been filed. PG&E argues that, with the station-specific assessments and its experience from the last rate case, it is confident that its proposed work pace for this program is reliable. However, PG&E notes that, because it is conducting on-going inspections and maintenance on the stations, it may need to reprioritize work as necessary to ensure its gas transmission system operates safely.[236]

PG&E disagrees with TURN's contention that PG&E did not provide an adequate explanation for exceeding the cost estimate for each project. PG&E asserts that, in its rebuttal testimony, it provided sufficient information to justify the reasonableness of the recorded costs. For example, PG&E provided a table that specifies for each project the reasons that it exceeded its forecasted budget for three of the "simple" station rebuild projects and the five complex station rebuild projects.[237] The reasons include that, for certain projects, PG&E was

[235] Cal Advocates Opening Brief at 61-62.

[236] PG&E Opening Brief at 7-31 to 7-33.

[237] PG&E Opening Brief at 7-41. It also provides justification for cost overruns for the complex station rebuild projects. *Id.* at

required to install a pig launcher, replace a stand-by generator, install automated valves, complete twice the number of regulator runs.

#### 7.3.3. Discussion

We find that PG&E's proposed pace of work for the M&C Station Rebuilds program is just and reasonable, subject to conditions. We are persuaded by PG&E's assertion that its new station-specific assessments and field verifications program has allowed PG&E to more accurately prioritize the station rebuild work and estimate the related costs. However, we share Cal Advocates' concern that obtaining five land permits per year could delay PG&E's pace of work if the permits are not granted timely. Accordingly, we direct PG&E to setup a one-way balancing account for the M&C Station Rebuild program.

We find that PG&E provided an adequate explanation for why it exceeded the average project estimate authorized for the 2015-2018 M&C Station Rebuild program and, therefore, decline to direct the disallowance that TURN requests.

### 7.4. M&C Terminal Upgrades

PG&E's three gas terminals are located in Milpitas, Antioch, and Brentwood. The M&C Terminal Upgrades program manages projects to perform regular upgrades and maintenance work on the terminals and to rebuild the Brentwood terminal (Brentwood Terminal Upgrade). PG&E states that it plans to rebuild the Brentwood terminal in multiple phases, with Phase I, which will replace piping, valves, and control equipment, occurring over the instant rate case period.[238]

PG&E forecasted the capital expenditures for this program using a three-year historical cost average from 2014-2016. PG&E states that it forecasted

[238] PG&E Opening Brief at 7-42.

the capital expense for Phase I of the Brentwood Terminal Upgrade project using detailed cost estimates developed by an engineering and consulting firm with experience in constructing gas transmission facilities.[239] PG&E's forecast of capital expenditures for this program is $7.4 million for 2019, $7.5 million for 2020 and $7.6 million for 2021.[240]

#### 7.4.1. Intervenors

Cal Advocates asserts that PG&E has not spent more than $1 million per year from 2016-2018 for terminal upgrade projects. Accordingly, Cal Advocates argues that the Commission should direct PG&E to establish a one-way balancing account for the M&C Terminal Upgrades program and extend the terminal upgrade projects into the next GT&S rate case by adjusting PG&E's capital estimate downward by 50 percent.[241]

TURN argues that PG&E's forecast for the terminal upgrade projects should be based on a six-year historical cost average from 2012-2017 as the additional cost data for 2012 and 2013 was in PG&E's workpapers and using a six-year average is the normal practice in rate cases. Based on this approach, TURN recommends a $0.5 million downward adjustment to PG&E's capital estimate for the terminal upgrade projects.

For the Brentwood Terminal Upgrade project, TURN states that PG&E confirmed that Phase I of the project is necessary regardless of whether PG&E decides to rebuild the Brentwood terminal. Thus, for the next rate case, TURN argues that PG&E should be required to provide a risk spend efficiency (RSE)

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[239] *Id.* at 7-43.

[240] *Id.* at 7-43.

[241] Cal Advocates Opening Brief at 62-63.

analysis of all the reasonable alternatives to rebuilding the terminal, and, if PG&E decides to proceed with the rebuild, it should perform an RSE analysis of the rebuilding options.[242]

#### 7.4.2. PG&E Response

PG&E argues that Cal Advocates does not provide adequate justification for its contention that PG&E should reduce its capital forecast for terminal upgrade projects by 50 percent. PG&E argues that Cal Advocates incorrectly based its recommendation on PG&E's past spending, which is problematic in this instance, because the scope of this program has been expanded to include rebuilding the Brentwood terminal.[243]

PG&E argues that the Commission should reject Cal Advocates' recommendation for a one-way balancing account for this program. PG&E asserts that the scope of work and related costs for this program has been sufficiently defined.[244]

PG&E argues that TURN's request for PG&E to perform a RSE analysis is outside the scope of this proceeding and should be rejected. In addition, PG&E argues, TURN's contention that the capital forecast for terminal upgrade work should be based on a six-year historical cost average is arbitrary and should be rejected. PG&E disagrees that using a six-year average is standard practice in rate cases as TURN has recommended a variety of forecasting approaches in the instant proceeding.[245]

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[242] TURN Opening Brief at 102-104.

[243] PG&E Opening Brief at 7-44 to 7-45.

[244] *Id.* at 7-45 to 7-46.

[245] PG&E Reply Brief at 7-4.

#### 7.4.3. Discussion

We find that PG&E's forecasted capital expenditures for the M&C Terminal Upgrade program are just and reasonable. We disagree with Cal Advocates' recommendation for a one-way balancing account for this program because the increase in the program's forecast over the last rate case is primarily due to the Brentwood Terminal Upgrade project.

We disagree with TURN's contention that PG&E's should use the six-year historical cost average from 2012-2017 to determine the capital forecast for this program. We find that, in this instance, cost data from the older years (*i.e.,* 2012 and 2013) would be outdated as they would not reflect the costs associated with technology changes that have occurred in the normal course of business.

With respect to the Brentwood Terminal Upgrade Project, we agree with TURN that, if PG&E proceeds with Phase II of the project or seeks an alternative approach, PG&E will need to justify its decision by, among other things, demonstrating that it had considered alternate solutions. However, we decline to specify the method that PG&E must use to perform its analysis.

### 7.5. M&C Station Over-Pressure Protection

The M&C Station Over-Pressure Protection program is a new PG&E program to manage projects that prevent large over-pressure events, which can cause pipeline equipment to malfunction or fail. PG&E defines an over-pressure event as a pressure exclusion that is 10 percent greater than the maximum allowable operating pressure for the pipeline equipment.[246] PG&E states that the expense activities include performing system studies that identify efficient options for providing over-pressure protection for specific stations, installing

[246] Exh. PG&E-1 at 7-58.

filters to reduce monitor failures, and providing program management to develop and maintain a master plan and schedule to eliminate or mitigate over-pressure events. PG&E states that the capital projects for this program will install secondary over-pressure protection at regulator stations.[247]

PG&E's expense forecast is based on the cost of specific activities, such as installing pilot filters and managing pilot studies on new valve technologies.[248] PG&E states that the cost estimates for the expense activities were provided by internal and external subject matter experts. PG&E forecasted capital expenditures using various technologies that provide over pressure protection.[249] PG&E request $6.1 million in capital expenditures for 2019, 2020, and 2021, and $1.6 in expenses for 2019.[250]

Cal Advocates argues that PG&E should maintain a memorandum account for this program as it is new and, therefore, PG&E does not have historical costs data from which it can generate a reliable forecast.[251] TURN argues that PG&E should revise the description of the program to reflect that it consists entirely of installing "slam-shut" devices at approximately 88 stations between 2019-2021.[252]

We recognize that managing over-pressure incidents on PG&E's gas transmission system is a priority, particularly considering that PG&E will rely on a new storage service, Inventory Management, to manage intra- and inter-day inventory imbalances. However, PG&E's vision of the program appears to be in

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[247] PG&E Opening Brief at 7-52.

[248] Exh. PG&E-1 at 7-59.

[249] PG&E Opening Brief at 7-52.

[250] *Id.* at 7-53.

[251] Cal Advocates Opening Brief at 64.

[252] TURN Opening Brief at 107.

flux. The description of the program in PG&E's testimony and Opening Brief are inconsistent with the description that PG&E provided to TURN in a data response. Thus, while we encourage PG&E to continue to evaluate the best methods to manage over-pressure incidents on its system, we find that requiring PG&E to track capital expenditures for this program in a memorandum account is appropriate until a firmer understanding of necessary activities and projects and the associated project costs can be forecast with a reasonable degree of accuracy.

### 7.6. M&C Gas Quality Assessment

The M&C Gas Quality Assessment program focuses on resolving gas quality issues that could negatively impact the operation of its equipment and ability to comply with the Commission's regulatory requirements for the quality of gas entering PG&E's system.[253] The scope of this program includes a variety of activities such as testing natural gas supplies to identify elemental sulfur, identifying corrosive pipe debris, and developing a new pipeline drying procedure.[254]

PG&E forecasts $1.0 million in expense for 2019, based on the escalated historical costs for the activities included in the scope of work for this program.[255]

Cal Advocates asserts that the 2017 recorded operation and maintenance expense for this program is $0.43 million, which is less than half of PG&E's proposed forecast. Accordingly, Cal Advocates recommends a $0.45 million downward adjustment to PG&E's forecast.

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[253] PG&E Opening Brief at 7-49.

[254] *Id.* at 7-49.

[255] *Id.* at 7-50.

PG&E argues that the recorded 2017 operation and maintenance expense for this program is not reflective of the costs that PG&E expects to incur in the future. PG&E asserts that its "limited spending" for this program was due to a one-time event that is not expected to occur on an "on-going basis."[256] Moreover, PG&E argues, using recorded 2017 costs as the sole basis for developing its 2019 forecast is inappropriate.

We find that PG&E's forecasted expenses for the M&C Gas Quality Assessment program is just and reasonable. We are persuaded by PG&E's assertion that the 2017 recorded operation and maintenance expense for this program excludes costs that PG&E expects to incur in 2019; accordingly, we do not adopt Cal Advocates' downward adjustment to PG&E's forecast.

### 7.7. M&C Routine Capital and Expense

The Routine M&C Capital and Expense program accounts for capital projects and expenses that do not qualify for the other M&C programs. PG&E states that the types of capital projects in this program include asset retirements and valve replacements.[257] The expense activities include assessing and repairing various equipment such as valves, monitors, controllers, electrical circuits, SCADA units, and meters.[258]

PG&E forecasted the capital expenditures and expenses for this program using an adjusted three-year average of historical costs from 2014-2016.[259]

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[256] *Id.* at 7-50.

[257] PG&E Opening Brief at 7-6.

[258] *Id.* at 7-26.

[259] PG&E adjusted for a large one-time project and projects related to new regulations. Exh. PG&E-1 at 7-47.

PG&E's 2019 expense forecast is $6.5 million, and its capital expenditure forecast is $38.5 million for 2019, $39.7 million for 2020 and $40.9 million for 2021.

Cal Advocates argues that PG&E's expense forecast for this program should be based on a five-year average of historical costs from 2012-2016 and include the large, one-time projects that PG&E excluded from its forecast. Under this approach, Cal Advocates asserts that PG&E's forecast would be $3.7 million for 2018 and 2019, which is a downward adjustment of $2.7 million.[260]

PG&E disagrees with Cal Advocates' recommendation. PG&E argues that its estimate includes additional costs to cover expenses for activities related to GHG emissions procedures and CARB oil and gas regulations, which will be effective staring in October 2017.[261] In addition, PG&E argues that Cal Advocates has not justified a reason for requiring PG&E to use two different methodologies (three-year and five-year average of historical costs) to forecast the expenses and capital expenditures for the same program.[262]

We find that PG&E's forecasted expense and capital expenditures for the M&C Routine Capital and Expense program is just and reasonable. No party opposed the capital forecast.

We are not persuaded by Cal Advocates' proposal to revise PG&E's expense forecast as the proposal would require PG&E to use older data and include outliers. Also, we note that Cal Advocates' forecast does not include the additional costs that PG&E estimates it will incur to comply with the new CARB regulations and GHG procedures.

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[260] Cal Advocates Opening Brief at 59-60.

[261] PG&E Opening Brief at 7-27.

[262] *Id.* at 7-28.

### 7.8. Critical Documents

PG&E states that the Critical Documents program focuses on revising and developing new critical drawings and documents to assist operations and maintenance personal with troubleshooting and operating the gas transmission system. PG&E states that the scope of work for this program includes three main activities: conducting field visits to prep the site, validating drawings and documentation, and updating existing drawings and documents consistent with Utility Standard TD-455IS, which was revised in 2017.[263]

PG&E states that the 2015 GT&S rate case deferred cost recovery for this program and ordered PG&E to track the program costs for Critical Documents work associated with stations built before January 1, 1956, in a memorandum account.[264]

PG&E's 2019 expense forecast for this program is $3.1 million. PG&E's forecast is based on cost from a pilot program that it performed to develop procedures, guidance, and standardized documents for its M&C and C&P programs.[265] PG&E's forecast includes the cost to address facilities built on or before December 31, 1955.

PG&E proposes to discontinue the memorandum account established for this program because, in its application, it proposes a forecast for work that excludes the work for which the Commission found cost recovery is inappropriate, namely, documentation for facilities built on or before December 31, 1955.[266] PG&E also proposes to eliminate the ECA Balancing

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[263] *Id.* at 7-56; *see also* Exh. PG&E-1 at 7-62.

[264] Exh. PG&E-1 at 7-63.

[265] PG&E Opening Brief at 7-56.

[266] *Id.* at 16-21.

Account for this program. The ECA balancing account was established by D.16-06-056 to track the difference between the adopted and actual cost of Phase 1 and 2 of the ECA work performed during the 2015 GT&S rate case cycle for stations installed on or before December 31, 1955, and certain station components installed on or after January 1, 1956.[267] PG&E 2019 forecast for this program is for work performed on components that have traceable, verifiable and complete records; thus, it argues that the balancing account is no longer necessary.

#### 7.8.1. Intervenors

Cal Advocates asserts that PG&E seeks to eliminate the memorandum and balancing accounts in this proceeding even through PG&E has yet to demonstrate that the account is no longer necessary. Accordingly, Cal Advocates argues that the Commission should reject PG&E's request.[268]

TURN also argues against PG&E's request to eliminate the memorandum account for the Critical Documents program.[269] TURN asserts that, in the 2015 GT&S rate case, the Commission directed PG&E to establish the memorandum account because of the likelihood that "some portion [of the cost of this program] will be to remediate prior deficient records management practices."[270] Thus, the Commission held that the memorandum account would ensure that PG&E recovers "only the costs to update existing station documentation or create new documentation to meet the standard set in Utility Standard TD 455IS" for

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[267] *Id.* at 16-22.

[268] Cal Advocates Opening Brief at 65-67.

[269] TURN Opening Brief at 109 (citing Exh. PG&E-1 at 7-7).

[270] *Id.* at 108 (citing D.16-06-056 at 139).

facilities built on or after December 31, 1955.[271] TURN argues that for the instant case, PG&E has not demonstrated that its forecast excludes costs incurred to remediate past deficiencies.

#### 7.8.2. PG&E Response

PG&E disagrees with Cal Advocates' contention that the memorandum account is necessary. PG&E asserts that it tracks the shareholder and ratepayer costs separately for this program. In response to TURN, PG&E argues that the expense activities for this program are necessary to standardize PG&E's documentation and are triggered by the vintage of the document, not the need to remediate deficient document management practices. Moreover, PG&E argues that it will continue to separately track costs for stations installed before January 1, 1956, and those installed on or after January 1, 1956.

#### 7.8.3. Discussion

We agree with intervenors that this program should continue to be tracked using the existing memorandum account. The program was only established during the last rate case, and PG&E has not demonstrated that its remedial activities have concluded. Thus, we find that PG&E should maintain the account at least until the next rate case where the Commission will be able to evaluate PG&E's progress and reassess the need for the memorandum account.

### 7.9. Station Assessments Programs

PG&E states that in anticipation of PHMSA's final rule for "new [Section] 192.624," proposed on April 8, 2016, PG&E initiated the Station Assessment Programs.[272] PG&E states that this program has two phases: Phase I

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[271] *Id.* at 108.

[272] Exh. PG&E-1 at 7-66 to 7-67.

consists of identifying and remediating issues that may compromise station asset integrity, and Phase II consists of performing any remaining remediation tasks identified from Phase I.[273] PG&E estimates that it will complete Phase I by the end of 2021.

PG&E states that the forecasted costs for Phase I includes technical engineering work and project planning. Using historical costs from 2016, PG&E estimates that the 2019 expenses for Phase I will be $4.7 million. For Phase II, PG&E estimates that its 2019 expenses will be $1.8 million.[274] PG&E performs strength testing when warranted as a result of the Phase I and Phase II findings. PG&E forecasts $1 million for the 2019 expense for performing station strength testing and $102,000 in capital expenditures for 2019.[275]

TURN does not oppose PG&E's estimates but argues that PG&E should be required to retain the one-way balancing account for this program. TURN asserts that its comparison of PG&E's recorded amounts for this program with the authorized levels vary significantly, warranting that PG&E continue to maintain the balancing account. For example, TURN asserts, for 2017, PG&E used only 2 percent of the authorized amount ($9.01 million was authorized and $0.20 was recorded).

PG&E argues that the Commission should reject TURN's recommendation. PG&E asserts an accounting adjustment is the primary reason that the recorded costs for this program are lower than the authorized costs.[276]

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[273] *Id.* at 7-66, 7-69.

[274] PG&E Opening Brief at 7-63.

[275] PG&E Opening Brief at 7-63.

[276] PG&E Opening Brief at 7-65.

We find that PG&E's forecasted expense and capital expenditures for the Station Assessments programs is just and reasonable, subject to conditions. As demonstrated by TURN, PG&E's forecast error for this program over the three-year period of the last rate case was substantial. While PG&E attributes the error to an accounting adjustment, we find that, given the degree of forecasting error from the last rate case, it is necessary for PG&E to continue to maintain the one-way balancing account that was established in D.16-06-056.

### 7.10. Physical Security

The Physical Security program focuses on projects that PG&E asserts are necessary to deter and prevent third-party damage and that implement security upgrades suggested in the Transportation Security Administration's guidelines. Under this program, PG&E will perform security upgrades at two stations per year. The upgrades will include installing locks, walls, fences, video surveillance technology, and advanced security barriers around PG&E's C&P and M&C assets.[277]

PG&E's forecast for this program area is based on the physical security upgrade projects that PG&E completed in 2015 and 2016, and includes costs for direct labor, material, construction, engineering, project management, and project support, such as land and permitting fees. PG&E's forecasted capital expenditures for this program are $9.4 million for 2019-2021.

TURN argues that PG&E's capital forecast is overstated. TURN asserts that PG&E's forecast includes the cost for only two projects that have an average cost of $4.57 million and were completed in 2016. TURN states that, through discovery, it learned that in 2017, PG&E implemented three more projects, all of

[277] PG&E Opening Brief at 7-67.

which cost less than the two projects in PG&E's forecast. TURN asserts that the average cost for the five projects that PG&E completed from 2016-2017 is $3.7 million. Thus, TURN argues that PG&E's forecast should be adjusted downward by $5.4 million. TURN also notes that PG&E stated that its forecast is not based on specific locations or on specific work tasks that PG&E plans to perform.[278]

PG&E asserts that "every station is unique," and that the projects that it completed in 2017 consist of one large station and two smaller stations. Thus, PG&E argues that TURN's "claim that the 2017 average may reflect cost savings is not correct" and, therefore, the Commission should reject TURN's recommendation.[279]

We find that PG&E's capital forecast for this program is just and reasonable, subject to conditions. PG&E states that each station is unique and, according to TURN, PG&E admitted that its forecast does not account for the station location. Accordingly, if PG&E upgrades mostly smaller stations, then the proposed forecast is likely overstated, but, if PG&E upgrades mostly larger stations, then the forecast could be an accurate reflection of the prospective recorded costs for this program. While the latter scenario is ideal, PG&E has not provided enough information (*i.e.,* station locations) to confirm that outcome. Thus, to ensure that ratepayers are refunded if PG&E primarily upgrades the smaller stations during the rate case period, we direct PG&E to establish a one-way balancing account to record these costs.

[278] TURN Opening Brief at 114.

[279] PG&E Opening Brief at 7-68.

### 7.11. Remaining Programs

#### 7.11.1. C&P Compressor Unit Control Replacements

PG&E states that most of its compressor units are installed with a PLC, which monitors and controls the operation of the compressor units and activates alarms. PG&E assert that the lifespan of a compressor unit PLC is between 15-20 years.[280] PG&E states that some of its PLCs are approximately 20 years old and the PLC manufacturer indicated that it would no longer support them.[281]

Accordingly, PG&E plans to replace two unit controls each year of the rate case period. PG&E states that the cost estimates were developed by an engineering and construction firm with relevant gas transmission experience.[282] PG&E's forecast of the capital expenditures and 2019 expenses for this program are in Tables 11 and 12, respectively.

#### 7.11.2. C&P Upgrade Station Control

PG&E states that, at its compressor stations, it has installed PLCs that interface with the PLCs at each respective compressor unit and the PLC input/output (I/O) interface module that receives information about the current operating conditions of the stations, among other things.[283] PG&E states that the PLC and I/O allow its operators to control the downstream pressure of incoming natural gas and eliminate deviations from normal operations.[284]

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[280] Exh. PG&E-1 at 7-37 to 7-39.

[281] PG&E Opening Brief at 7-8 to 7-9.

[282] *Id.* at 7-9.

[283] Exh. PG&E-1 at 7-40.

[284] PG&E Opening Brief at 7-8.

PG&E asserts that the manufacturer of the PLCs and I/O interface modules indicated that it will no longer support these products in the near future. As such, PG&E states, it plans to complete one station control upgrade each year of the rate case period. PG&E states that the cost of the upgrades are based on a cost estimate developed by an engineering and construction firm with relevant gas transmission experience.[285] PG&E's capital expenditure forecast for this program is in Table 13.

**Table 13 – Upgrade Station Control Summary of Capital Expenditures ($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Upgrade Station Control | 76T | $2,014 | $2,022 | $2,018 |

### 7.11.3. C&P Emergency Shutdown System

PG&E has installed ESD systems at its compressor stations and underground gas storage facilities. The EDS systems are designed to detect gas leaks and fires, among other hazardous events.[286] Upon detecting a hazardous event, PG&E states that the ESD system will safely stop operating the equipment, isolate the station piping, and vent the gas.

PG&E asserts that some of its stations have gas and fire detection sensors that use outdated technology. Accordingly, PG&E proposes to replace two ESD systems each year in the rate case period.[287] Each ESD system could require up to 15 fire detection sensors and 10 gas detection sensors.[288] PG&E asserts that the replacement costs are based on a cost estimate developed by an engineering and

[285] *Id.* at 7-7.

[286] PG&E-1 at 7-32.

[287] PG&E Opening Brief at 7-7.

[288] Exh. PG&E-1 at 7-34.

construction firm with relevant gas transmission experience.[289] PG&E's capital expenditure forecast for this program is in Table 14 below.

**Table 14—Emergency Shutdown Upgrades**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Emergency Shutdown Upgrade | 76F | $3,843 | $3,857 | $3,850 |

#### 7.11.4. C&P Gas Transmission Upgrades – Hinkley and Topock

This program upgrades electrical equipment, such as switch gear sections and motor control center sections, at the Hinkley and Topock compressor stations. PG&E states that the switch gear sections protect the electrical generation equipment and related circuits at the compressor stations.[290] PG&E states that the motor control center section controls various devices at the compressor stations such as electric motors, valves, air compressors, water pumps, and the electric motor drive for gas compressor units.[291]

PG&E forecasted the capital expenditures for this program using cost estimates developed by an engineering and construction firm with experience in the construction of gas transmission facilities. PG&E's capital expenditure forecast for this program is in Table 14 above.

#### 7.11.5. Facility Integrity Management Program

PG&E states that it uses FIMP as a risk management program to identify and adopt best practices for managing its facility assets. The FIMP program includes various activities such as improving data acquisition and analysis tools,

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289 PG&E Opening Brief at 7-8.

290 Exh. PG&E-1 at 7-35.

291 *Id.* at 7-35.

performing pilot programs to assess new technologies and processes, and developing station-specific risk management capabilities.[292]

PG&E's forecast for the FIMP program is based on estimated costs for the various activities necessary for program development, risk assessment, strategy, support, and technical assessments. PG&E's 2019 expense forecast for this program is $2.8 million.[293]

#### 7.11.6. Becker Upgrade Program

PG&E proposes to upgrade the operational capabilities of the Becker Control Valve system. PG&E asserts that this program will address equipment related issues that impact the reliability of its gas system.[294] PG&E forecasted the costs for this project using the cost of individual projects planned for 2019 and excluded irrelevant costs. PG&E's 2019 forecast of capital expenditures for the Becker System Upgrade is $325,000.[295]

#### 7.11.7. Discussion

We find that PG&E's forecast for the C&P Compressor Unit Control Replacements, C&P Upgrade Station Control, C&P Emergency Shutdown System, C&P Gas Transmission Upgrades – Hinkley and Topock, FIMP, and Becker System Upgrades programs are just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. No party opposes these forecasts. Accordingly, we adopt PG&E's 2019 expense forecast for the FIMP program, and its forecasted capital expenditures for the C&P

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292 PG&E Opening Brief at 7-5.

293 *Id.* at 7-5.

294 Exh. PGE-1 at 7-48.

295 PG&E Opening Brief at 7-49.

Compressor Unit Control Replacements, C&P Upgrade Station Control, C&P Emergency Shutdown System, C&P Gas Transmission Upgrades – Hinkley and Topock, and Becker System Upgrades programs.

### 8. Asset Family – Transmission Pipeline

The objective of the programs in PG&E's Transmission Pipeline Asset Family is to assess and mitigate pipeline safety and integrity risks and respond to pipeline failures.[296] PG&E's steel pipes have a diameter of between less than four inches and 42 inches, are coated to prevent corrosion, and have a seam.[297] PG&E states that the average age of its steel pipes is 45 years old. PG&E operates and maintains approximately 6,600 miles of transmission pipeline and related equipment that, together, transport gas from receipt points to PG&E's transmission system where the gas is then transported to either a distribution center, storage facility, or large customer. PG&E states that a significant portion of its local transmission system is located in densely-populated areas, whereas its backbone transmission system is primarily located in rural areas.[298]

Some of the programs in the Transmission Pipeline Asset Family were established based on information from PG&E's Pipeline Safety Enhancement Plan (PSEP).[299] The risks PG&E seeks to mitigate include corrosion, which is primarily caused by the passage of time; manufacturing, construction, and equipment defects; and damage caused by third-parties, weather, and operator errors.

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[296] *Id.* at 5-1.

[297] Exh. PG&E-1 at 5-14.

[298] Exh. PG&E-1 at 5-13 to 5-14.

[299] *Id.* at 5-10.

The programs supporting the Transmission Pipeline Asset Family are: (1) Pipe Inspections (In-Line Inspections (ILI), Direct Assessment, and Hydrostatic Testing), (2) Pipe Replacements, (3) Earthquake Fault Crossings, (4) Geo-Hazard Threat Identification and Mitigation, (5) Identification and Mitigation Support, (6) Emergency Response Programs, (7) Class Location Change, (8) Shallow and Exposed Pipe, (9) Gas Gathering, (10) WRO, and (11) Pipe Investigation and Field Engineering.

PG&E's capital expenditures and 2019 expense forecasts for this program are in Tables 15 and 16, respectively.

**Table 15 – Capital Forecast for Transmission Pipeline Assets[300]**
**($ Thousands of Nominal Dollars)**

| Line No. | Program | MWC | PG&E 2019 Forecast | PG&E 2020 Forecast | PG&E 2021 Forecast |
|---|---|---|---|---|---|
| 1 | ILI | 98 | $213,526 | $220,235 | $226,708 |
| 2 | Hydrostatic Testing | 44, 73, 75 | 49,897 | 51,465 | 52,978 |
| 3 | Pipe Replacement | 75 | 47,935 | 51,850 | 42,879 |
| 4 | Earthquake Fault Crossings | 75 | 12,231 | 12,616 | 12,986 |
| 5 | Geo-Hazard Threat Identification and Mitigation | 75 | 4,487 | 4,628 | 4,754 |
| 6 | Emergency Response | 75 | 55,410 | 60,233 | 57,584 |
| 7 | Class Location Change | 75 | 5,498 | 5,636 | 5,773 |
| 8 | Shallow/Exposed Pipe (Including Water and Leven) | 44, 75 | 25,446 | 26,246 | 27,017 |
| 9 | Gas Gathering | B84 | 3,971 | 4,096 | 4,216 |
| 10 | WRO | B83 | 27,886 | 28,742 | 29,567 |
| 11 | Total Capital Expenditures | | $446,270 | $486,747 | $464,492 |

[300] PG&E Opening Brief at 5-4.

**Table 16– 2019 Expense Forecast for Transmission Pipeline Assets**[301]
**($ Thousands of Nominal Dollars)**

| Line No. | Program | MWC | PG&E Fixed Forecast | PG&E Errata (a) (d) | PG&E Current Forecast |
|---|---|---|---|---|---|
| 1 | In-Line Inspections (ILI) | 34, HP | $125,820 | $(1,339) | $124,481 |
| 2 | Direct Assessments | HP | 35,107 | - | 35,107 |
| 3 | Hydrostatic Testing | 34, GM, HP, JT | 155,702 | (19,399) | 136,303 |
| 4 | Pipe Replacements | JT | 4,111 | (19) | 4,092 |
| 5 | Earthquake Fault Crossings | JT | 1,372 | - | 1,372 |
| 6 | Geo-Hazard Threat Identification and Mitigation | HP, JT | 2,841 | - | 2,841 |
| 7 | Programs to Support Transmission Integrity Management Program (TIMP) | HP | 14,248 | - | 14,248 |
| 8 | Emergency Response | JT | 5,281 | (906) | 4,375 |
| 9 | Class Location Change | JT | 3,305 | (1,124) | 2,181 |
| 10 | Shallow/Exposed Pipe (Including Water and Levee Crossings) | 34, JT | 1,061 | 52 | 1,113 |
| 11 | Work Required by Others (WRO) | JT | 716 | (1) | 715 |
| 12 | Pipe Investigations and Field Engineering | JT | 8,743 | (3) | 8,740 |
| 13 | Other | 34, II | - | - | - |
| 14 | Total Expenses | | $358,307 | $(22,728) | $335,568 |

### 8.1. Pipe Inspections

PG&E uses three methods to inspect its pipelines: ILIs (traditional and non-traditional), direct assessment, and hydrostatic testing. Also, in certain instances, PG&E will replace steel pipes in lieu of inspecting them.

#### 8.1.1. ILI Program

PG&E's ILI program consists of using inspection tools, called smart pigs, to inspect the internal and external condition of the transmission pipeline, and collect data on abnormalities that may require further investigation or pipeline

[301] PG&E Opening Brief at 5-3.

repairs. ILIs also provide the thickness of the pipe wall and other geometric data.[302]

PG&E asserts that D.11-06-017, as codified by Section 985, requires natural gas transmission pipelines in California to be capable of in-line inspections, where warranted.[303] In addition, PG&E asserts that in-line inspection "is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe."[304] Accordingly, PG&E plans to perform in-line inspections on 65 percent of its pipeline system by the end of 2026.[305]

There are two types of in-inline inspections: traditional and non-traditional. Both methods use a "smart pig," a devise that moves inside of the pipe and uses sensors to detect abnormalities. The different between the two methods is the way that the smart pig moves through the pipeline. For traditional in-line inspections, the smart pig is transported by the pressure generated from the gas flow; whereas, for non-traditional in-line inspections, the smart pig moves through the pipe using a robotic tool or tractor. PG&E states that the pipeline conditions necessary for non-traditional in-line inspections are more restrictive than for traditional ILIs; thus, PG&E estimates that three percent of its pipelines will be inspected using non-traditional ILIs tools.[306]

PG&E states that there are three major phases to this program. For Phase I, PG&E will upgrade selected pipeline segments by installing equipment to launch

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[302] Exh. PG&E 1 at 5-23.

[303] *Id. at* 5-25.

[304] PG&E Opening Brief at 5-13.

[305] Exh. PG&E-1 at 5-27; PG&E Opening Brief at 5-14.

[306] *Id.* at 5-21.

and receive smart pigs. PG&E states that non-traditional inspections do not required upgrades, so Phase I is only applicable to traditional ILIs.[307] For Phase II, PG&E must run a baseline assessment of the pipeline segment, configure the smart pig based on the type of issue that needs to be examined, and perform the inspection. For Phase III, PG&E will remediate the pipe based on the extent and degree of the abnormalities that the inspection identifies. PG&E states that federal safety regulations and its integrity management program prescribe the remedial actions that is required to address identified abnormalities.[308]

PG&E states that in D.16-06-056, the Commission authorized it to implement the in-line upgrades (Phase I) using a 12-year pace. However, PG&E states that since that decision, it has added 24 sections or 237 miles of pipeline that should receive in-line inspections. Thus, to remain on the 12-year pace, PG&E proposes to implement 18 upgrades for each year in the rate case period.[309] Table 17 provides PG&E's status and plan for updating its pipelines to accommodate using smart pigs for ILIs.

**Table 17 -- In-line Upgrade (ILI) Program[310]**

| Line No. | ILI Upgrade Period | Approximate Pipe Miles | HCA Miles (a) |
|---|---|---|---|
| 1 | Upgraded through 2016 | 1.797 | 568 |
| 2 | 2017-2018 Planned | 462 | 58 |
| 3 | 2019-2021 Planned | 1,108 | 213 |
| 4 | 2022-2026 Planned | 899 | 138 |
| 5 | Total | 4,256 | 977 |

(a) High Consequence Area (HCA)

[307] PG&E Opening Brief at 5-28.

[308] Exh. PG&E-1 at 5-23.

[309] PG&E Opening Brief at 5-14 to 5-15.

[310] Exh. PG&E-1 at 5-27, Table 5-9.

PG&E estimates that the capital expenditures for performing 18 upgrades per year using the historical costs of upgrades that it completed between 2013 and 2015, escalated for 2019-2021. PG&E's capital expenditure forecast for performing in-line upgrades is in Table 18 below.

PG&E expects to conduct 75 traditional ILIs (Phase II) over the rate case period. PG&E states that 43 of the projects will be first-time runs, bringing the total of pipeline miles inspected to 47 percent of its entire system by the end of 2021. PG&E states that the remaining 32 projects will be reassessments, which are inspections of pipelines that have already had at least one ILIs.[311]

PG&E estimates the costs to perform traditional in-line inspections based on the type of inspection tool. To calculate the cost for using the Magnetic Flux Leakage (MFL) inspection tool, PG&E developed a cost curve using historical project costs from 2014 to 2016. The cost curve provides a formula for calculating the cost of an MFL inspection based on the maximum diameter and mileage of the pipeline segment. For projects that require the Traverse Flux Inspection tool, PG&E estimates the average cost for an inspection using vendor quotes. For projects that require Electro-Magnetic Acoustic Transducer (EMAT) inspection tools, PG&E used vendor cost estimates and the cost estimates from the 2015 EMAT inspection that it performed on Line 400.[312] PG&E's 2019 expense forecast for traditional ILIs is in Table 18 below.

PG&E states that it will conduct approximately 47 non-traditional inspections over the rate case period.[313] PG&E estimates the cost for the

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[311] *Id.*

[312] *Id.* at 5-30.

[313] *Id.* at 5-27.

non-traditional in-line inspections using a cost curve that is based on the historical project costs completed between 2014 and 2016.[314] PG&E's 2019 expense forecast for non-traditional in-line inspections is in Table 18 below.

For the remediation activities (Phase III), PG&E forecasts that it will need to perform 465 Direct Examination and Repair (DE&R) digs over the rate case period.[315] PG&E states that the excavations generally occur within one year of the inspection. Using historical data from previous excavation, repair, and replacement projects, PG&E states that each DE&R dig will cost $251,000, plus escalation. PG&E's 2019 expense forecast for non-traditional ILIs is in Table 18 below.

**Table—18 Summary of Expenses[316]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2018 Forecast | 2019 Forecast |
|---|---|---|---|---|
| 1 | Traditional ILI | HPB, 34A | $32,705 | $66,718 |
| 2 | Non-Traditional ILI | HPR | 10,882 | 19,815 |
| 3 | ILI DE&R | HPI, 34A | 26,093 | 38,959 |
| 4 | PSEP Pipelines ILI | KE3 | - | - |
| 5 | Total ILI Expenses | | $69,681 | $125,492 |

[314] *Id.* at 5-31.

[315] *Id.* at 5-28. PG&E estimates that it will perform .25 digs per each mile of pipe that is inspected. *Id.* at 5-31.

[316] *Id.* at 5-32, Table 5-10; *see also* PG&E Opening Brief at 5-23 and 5-28.

**Table 19--Summary of Capital Expenditures[317]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2016 Recorded | 2017 Forecast | 2018 Forecast | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|---|---|---|
| 1 | ILI Capital Upgrades | 98C, 44A | $138,390 | $80,105 | $90,619 | $213,526 | $220,235 | $226,708 |
| 2 | ILI Capital Repair | 75P | 172 | 1,600 | 2,000 | - | - | - |
| 3 | PSEP ILI Pipeline Retrofit | 2H4 | 37 | - | - | - | - | - |
| 4 | Total ILI Expenses | | $138,599 | $81,705 | $92,619 | $213,526 | $220,235 | $226,708 |

#### 8.1.2. Intervenors

##### 8.1.2.1. In-Line Upgrades

Some intervenors argue that PG&E's pace for performing upgrades -18 projects per year—is unrealistic. TURN argues that from the time PG&E started performing the inline inspection (2012-2017) it has only implemented an average of 4.8 projects per year, with 10 being the most upgrades that PG&E has performed in a year.[318] Thus, TURN recommends that forecasting for nine projects per year would be reasonable as it is just below the number of projects that PG&E has demonstrated that it can perform on an annual basis.[319] TURN asserts that PG&E has categorized each project based on priority, with Tier 1 being the highest. TURN asserts that, because PG&E will complete the Tier 1 projects by the end of 2018, a reduced pace of nine projects per year would not delay inspections for the high priority pipeline segments.[320]

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[317] *Id.* at 5-32, Table 5-11.

[318] TURN Opening Brief at 43.

[319] *Id.* at 47.

[320] *Id.* at 46.

Similarly, based on PG&E's track record, Cal Advocates argues that the pace of upgrade projects should be reduced to 12 per year.[321] CSU argues that PG&E has not demonstrated that it has the inventory, equipment, and trained resources to implement 18 upgrade projects per year.[322] Indicated Shippers argues that PG&E's should upgrade pipelines at a pace that will allow it to complete upgrading pipelines within 15 years, rather than at a 12-year pace.[323] Indicted Shippers argues that a 15-year pace would ensure that PG&E had sufficient budget to complete high-priority in-line upgrades to pipelines in HCA and high Impact Occupancy Count areas by the end of 2029.[324]

#### 8.1.2.2. Traditional and Non-Traditional In-line Inspections

TURN states that, in its testimony, it demonstrated that the cost curve that PG&E used to calculate its estimate for performing traditional in-line inspections generates inaccurate results.[325] Thus, as an alternative, TURN recommends that PG&E forecast costs for this program using a methodology that is based on the average cost per length times diameter.[326] TURN asserts that, in PG&E's rebuttal testimony, PG&E agreed to use TURN's methodology.[327] Cal Advocates agrees with TURN's capital expenditure forecast methodology for traditional ILIs.

Because, as noted earlier, TURN argues that PG&E should reduce its forecasted pace of work for performing in-line upgrades, TURN argues that the

[321] Cal Advocates Opening Brief at 31.

[322] CSU Opening Brief at 4-5.

[323] Indicated Shippers Opening Brief at 14.

[324] *Id.* at 15.

[325] TURN Opening Brief at 50.

[326] *Id.* at 50.

[327] *Id.* at 50.

associated amount of inspections should also decrease as fewer pipes will be upgraded to accommodate smart pigs during the rate case period. Thus, TURN argues that PG&E's forecast for this program should be reduce by $19 million to account for TURN's recommendation to implement nine ILI upgrades per year.[328]

Cal Advocates argues that PG&E should not perform the forecasted re-assessment work as it is not required under relevant law (*i.e.,* 49 CFR § 192.937(c) (2018)). Cal Advocates disagrees with PG&E's contention that the reassessments are necessary based on PG&E's risk assessment approach. Cal Advocates argues that PG&E has not demonstrated, using quantitative evidence, that performing the reassessments are necessary to reduce pipeline safety and operational risks.[329] Accordingly, Cal Advocates argues that the Commission should adopt the scope of work stated in Table 3 of its Opening Brief.[330]

For non-traditional in-line inspections, TURN states that it adopted PG&E's methodology, which uses the average of historical project costs from 2014-2016, but argues that PG&E should include cost data from 2017, which would reduce PG&E's estimate by $1.0 million.[331] Cal Advocates agrees with TURN's proposal. Cal Advocates also argues that PG&E's pace of work—11.75 miles per year—is unrealistic and, therefore, recommends that PG&E

[328] *Id.* at 51.

[329] Cal Advocates Opening Brief at 24-26.

[330] *Id.* at 24-26.

[331] TURN Opening Brief at 52.

remove the reassessment work, which would reduce the pace of non-traditional inspections by 2.3 miles per year.[332]

#### 8.1.2.3. Direct Examination & Repair

Cal Advocates argues that, because PG&E's estimate of DE&R digs is directly proportionate to the number of in-line inspections, PG&E should reduce its forecast for this program accordingly. Cal Advocates asserts that PG&E's forecast should be based on the mileage of in-line inspections performed during 2018-2020. Based on that timeframe, Cal Advocates estimates that PG&E's 2019 expenses should be $38.9 million, which accounts for 348 digs, rather than 465 digs as proposed by PG&E.[333]

TURN argues, and Cal Advocates agrees, that PG&E's cost estimate for performing digs should include 2017 costs.[334] In addition, TURN argues that PG&E's proposal to round up the number of digs should be rejected.

#### 8.1.2.4. PG&E Response

PG&E reiterates that, to remain on a 12-year pace, it will need to perform 18 upgrades for each year in the rate case period. PG&E argues that it has adequately planned for the resources needed for it to implement 18 projects per year. In fact, PG&E asserts that, with the requisite funding, it is capable of implementing more than 18 projects per year.[335] Thus, PG&E argues that the pace of work for the in-line upgrades and related inspections should remain unchanged.[336] Alternatively, PG&E argues, if the Commission decides to reduce

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[332] Cal Advocates Opening Brief at 28.

[333] *Id.* at 29.

[334] Cal Advocates Opening Brief at 30; TURN Opening Brief at 52-54.

[335] PG&E Opening Brief at 5-18 to 5-19.

[336] *Id.* at 5-26.

the pace of work, PG&E requests that the Commission consider authorizing at least 16 upgrade projects per year so that it would only need to defer four pipeline segments to the next rate case.[337]

PG&E confirms that it accepts TURN's forecast methodology for estimating costs for the in-line upgrade projects but disagrees with TURN's contention that PG&E should reduce the pace of work for performing in-line upgrades and related inspection runs.

PG&E argues that Cal Advocates' contention that PG&E should perform reassessments only when warranted by 49 CFR § 192.937(c) is inconsistent with the requirement from D.16-06-056 that PG&E establish a 12-year pace of work to make its system suitable for in-line inspections where possible. Moreover, PG&E argues, Cal Advocates' approach fails to "represent a prioritized response to risk rather than a compliance effort."[338] PG&E also argues that the reassessments are "compliance-driven work."[339]

PG&E disagrees with TURN's contention that PG&E's forecasted expenses for traditional and non-traditional in-line inspections, and DE&R work should include 2017 data. PG&E argues that, for this application, it has constantly based its forecasts on data through 2016 because that was the most recent historical year available when its application was filed.[340]

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[337] *Id.* at 5-28.

[338] PG&E Opening Brief at 5-26.

[339] PG&E Comments on Proposed Decision at 12 (citing Exh. PG&E-5, WP 5-38 (List of In-line Inspection projects for 2019-2021) and WP 5-44 (List of completed digs).

[340] *Id.* at 5-27.

#### 8.1.3. Discussion

We are persuaded by the intervenors who contend that PG&E's past performance for implementing in-line upgrades demonstrates that there is a high likelihood that PG&E will not be able to implement 18 in-line upgrade projects per year. Between 2015 and 2018, the period covered by D.16-06-056, which required the 12-year pace, PG&E completed an average of only 6.75 upgrade projects per year, a 26-year pace.

We find that using Cal Advocates' pace of 12 projects per year is reasonable. As TURN noted, in 2015, PG&E demonstrated that it can complete 10 upgrade projects over the course of one year. Further, PG&E attests that it is "mobilizing" to implement the in-line upgrades; thus, we find that it is likely that PG&E will be able to implement two projects over the highest amount that it has previously implemented.

However, we do not prohibit or discourage PG&E from performing more than 12 upgrade projects per year during the rate case period. To that end, we direct PG&E to establish a memorandum account for the In-Line Inspection Program to track the costs for upgrades that exceed the authorized pace, among other related expenditures.[341] For example, if the rate case period is three years, then after PG&E completes at least 36 projects, it may record expenses for any additional projects in the new memorandum account. By allowing PG&E to use a memorandum account, this decision gives PG&E the ability to complete 18 projects per year and seek cost recovery for the work and, therefore, remain on track with the 12-year pace established by D.16-06-056. Thus, we find that

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[341] We also direct PG&E to use the new memorandum account for in-line inspection runs and DE&R work.

PG&E's argument that reducing the pace of work for upgrades would require PG&E to implement alternative inspection methods is moot.

We find that the 12-project/year pace would not pose undue risks. As TURN asserted, PG&E stated that it will upgrade the Tier 1 pipeline segments by the end of 2018. With respect to the reassessment work that PG&E plans to perform using tradition in-line inspections, we find that, while the reassessments may not be required by law, PG&E may still perform them, provided that the risks associated with foregoing the reassessments are greater than the risks of foregoing first-time assessments for traditional in-line inspections of pipeline segments that are categorized as Tier 1 and Tier 2. We permit PG&E to use the memorandum account, directed above, to record the costs for the reassessment work.

Because we are reducing PG&E's pace of work for in-line upgrades to 12 projects per year, we agree with TURN and Cal Advocates that PG&E's forecasts for the related traditional and non-traditional in-line inspections, and DE&R digs should also be reduced accordingly. If, however, PG&E completes more than 12 in-line upgrades for every year in the rate case period, we find that PG&E may also perform additional inspections and track the costs for such inspections in the new In-Line Inspection Program memorandum account, discussed earlier. The revised pace of work for in-line inspections and DE&R digs are in Appendix D. If, however, PG&E performs less work, we find that PG&E should refund ratepayers because of PG&E's history of underperforming work for this program. Accordingly, we direct PG&E to establish a one-way balancing account for this program.

With respect to the methodology for forecasting capital expenditures for in-line upgrades, PG&E agrees to use TURN's methodology and no party opposes that approach. Accordingly, we adopt PG&E's revised capital expenditure forecast, as adjusted to reflect TURN's recommendations. For PG&E's 2019 expenses for non-traditional in-line inspections and DE&R digs, we agree with TURN's contention that PG&E's forecast should include 2017 data.

Accordingly, we adopt the revised capital expenditure and 2019 expense forecasts for this program, as stated in Appendix D.

#### 8.1.4. Direct Assessment

Direct assessment is a method for inspecting the integrity of steel pipes to detect external corrosion, internal corrosion, and stress corrosion cracks. PG&E plans to perform two types of direct assessments during the rate case period: external corrosion direct assessments (ECDA) and internal corrosion direct assessments (ICDA).[342]

PG&E implements direct assessments using four-steps: (1) pre-assessment, (2) indirect inspection, (3) direct examination, and (4) post-assessment. The indirect inspection step involves performing a diagnostic test on the pipe and the direct examination step involves physically examining the pipeline at specific locations. PG&E proposes to replace direct assessment projects with hydrostatic tests and in-line inspections, with limited exceptions such as for reassessing pipelines that are ineligible for hydrostatic test or for inspecting pipelines that have not been upgraded with ILI equipment.[343]

PG&E plans to conduct ICDAs on approximately 3.5 miles of pipeline located in HCAs and ECDAs on approximately 304 miles of pipeline located in

[342] PG&E Opening Brief at 5-29.

[343] PG&E Opening Brief at 5-29 to 5-30.

HCAs.[344] PG&E forecasts the costs for the ECDA projects using several factors: (1) average cost per mile to complete surveys, (2) historical dig rate per mile assessed using historical data from projects completed between 2014 and 2016, and (3) average ECDA cost per dig using projects completed between 2014 and 2016. PG&E estimates that it will perform two digs per mile when the ECDA project is a reassessment, and four digs per mile when the ECDA project is a first-time assessment. PG&E forecasts the cost for ICDA projects using historical engineering and direct examination costs for ICDA projects.[345] PG&E's proposed 2019 expense forecast for ECDA and IDCA projects is in Table 20.

**Table 20 - PG&E Proposed 2019 Expense Forecast[346]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | ECDA | HPC, HPN | $31,387 |
| 2 | ICDA | HPJ, HPO | $3,720 |
| | Total | | $35,107 |

#### 8.1.4.1. Intervenors

Cal Advocates argues that PG&E has not provided adequate support to demonstrate that PG&E's estimated pace—two digs per mile where the ECDA project is a reassessment, and four digs per mile where the ECDA project is a first-time assessment—is reasonable. Cal Advocates argues that PG&E has provided inconsistent descriptions and measurements for the pace of work of ECDAs, making it difficult for Cal Advocates to review PG&E's forecast.[347] Cal Advocates also argues that PG&E's forecast for the ECDA work should be

344 *Id.* at 5-30.

345 Exh. PG&E-1 at 5-38.

346 PG&E Opening Brief at 5-31.

347 Cal Advocates Opening Brief at 35-36.

reduced to reflect that PG&E is planning to transition from direct assessments to other types of pipeline inspection techniques. During the 2015 GT&S rate case, PG&E performed 257 miles of ECDA work, yet for 2019-2021, PG&E plans to perform ECDA work on 304 miles. Accordingly, Cal Advocates argues that the PG&E's 2019 expense forecast for ECDA work should be reduced to $17.6 million.[348]

TURN argues that PG&E's 2019 expense forecast should be reduced to reflect a disallowance for deferred work. TURN asserts that in D.16-06-056, the Commission authorized PG&E to perform 505 miles of ECDAs and 81 miles of ICDA, but that PG&E performed only 324 miles and five miles, respectively. TURN asserts that the Deferred Work Settlement that the Commission adopted in the 2017 GRC proceeding provides that PG&E must demonstrate that its decision to defer work between rate cases is consistent with six principles.[349] TURN argues that, for the deferred ECDA work, PG&E has not meet the six principles, in part because PG&E has not demonstrated that it reprioritized the deferred ECDA work.[350]

Specifically, TURN argues that PG&E's explanation that it reprioritized the direct assessment work to perform TIMP pressure testing is unsupported. TURN argues that D.16-06-056 authorized PG&E to perform pressure tests for the TIMP program and to comply with D.11-06-017. TURN asserts that, during the hearing, PG&E's witness Barnes, admitted that PG&E had reduced the pressure tests required by D.11-06-017 so that PG&E could perform additional TIMP

[348] *Id.* at 35-36.

[349] *Supra* at 5-6.

[350] TURN Opening Brief at 59.

pressure tests. Thus, TURN argues, "[t]here was no additional pressure testing work that needed to be offset" by resources allocated to perform ECDA work."[351]

Moreover, TURN argues that PG&E is not required to perform the deferred work during the instant rate case period.[352] TURN argues that PG&E's testimony during the 2015 rate case misled the Commission by stating that PG&E was required to perform the direct assessments that it later deferred. TURN asserts that Barnes admitted that the pipelines for which PG&E deferred direct assessments were reclassified, which changed the assessment interval such that the associated pipeline segments are not required to be assessed until 2027.[353] Accordingly, TURN argues that PG&E's shareholders should fund a portion of the deferred direct assessments that PG&E scoped into the instant proceeding.

In calculating its proposed disallowance for the ECDA work, TURN states that shareholders should fund 181 miles of ECDA work as that represents the ECDA work that ratepayers funded in the previous rate case. TURN asserts that in the instant rate case, PG&E plans to perform 304 miles of ECDA work and 3.5 miles of ICDA work. Since 181 is 59.4 percent of ECDA mileage that PG&E states it will assess in the instant rate case period, TURN asserts that "shareholders should pay for 59.4 percent of the proposed ECDA mileage for each year of the rate case."[354] Thus, TURN asserts, "for the test year, this means that that shareholders would pay for 57 miles and ratepayers would pay for

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[351] TURN Opening Brief at 56-57.

[352] *Id.* at 58-59.

[353] *Id.* at 56-57.

[354] TURN Opening Brief at 60.

39 miles . . . . ,[355] resulting in a downward adjustment to PG&E's ECDA 2019 expense forecast of $18.6 million.[356]

Cal Advocates argues that, because PG&E plans to perform ICDA work on 0.7 miles of pipeline, the Commission should direct PG&E to use a memorandum account to track PG&E's 2019 expense forecast of $3.7 million. Moreover, Cal Advocates argues, PG&E's track record with this program suggests that a memorandum account is necessary as in the 2015 GT&S case, PG&E requested funds to perform 81 miles of ICDA work but only assessed 6.2 miles.[357] TURN argues that PG&E's proposal to perform 3.5 mile of ICDA work is a small percentage of the 76 miles that it deferred; thus, TURN argues, PG&E's shareholders should be required to fund all of the IDCA work for the instant rate case.[358]

#### 8.1.4.2. PG&E Response

PG&E disagrees with Cal Advocates' contention that PG&E has not supported its forecasted pace of work for the ECDA activities. PG&E argues that the National Association of Corrosion Engineer's standards number SP0502, which is incorporated by reference into 48 CFR Part 192, Subpart O, requires PG&E to perform four digs for a baseline assessment and a minimum of two digs for reassessments.[359] PG&E disagrees with Cal Advocates' contention that its ECDA forecast should be reduced to reflect PG&E's plan to replace direct assessments with other inspection techniques. PG&E argues that it is

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[355] *Id.*

[356] *Id.*

[357] Cal Advocates Opening Brief at 37.

[358] TURN Opening Brief at 60.

[359] PG&E Opening Brief at 5-35.

transitioning where possible; thus, in certain instances it will continue to perform direct assessments.[360]

PG&E states that it deferred the direct assessment work, authorized in the previous rate case, so that it could perform TIMP pressure tests. PG&E states that the 2015 rate case authorized $42.36 million to perform TIMP pressure tests during 2015-2018, but it was required to spend $125.55 million.[361]

#### 8.1.4.3. Discussion

We agree with TURN that, of the 305 miles that PG&E seeks authority to perform ECDA work, 181 miles are deferred from the prior rate case. We differ, however, on the amount of deferred work that should be disallowed from cost recovery. PG&E asserts that, because it spent three times the amount that D.16-06-056 authorized for the TIMP program, it has demonstrated that it reprioritized the ECDA work such that it diverted staff and other relevant resources from the ECDA program. On the other hand, TURN's cross-examination of PG&E's witness demonstrates that at least some, if not all, of the TIMP work was performed by diverting staff and resources from the pressure testing that PG&E was authorized to perform to comply with D.11-06-017.

After weighing the competing evidence presented by PG&E and TURN, we find that, while TURN's evidence is more credible, it does not completely disprove PG&E's assertion. TURN's evidence was derived from cross-examination, a trial procedure that tests the veracity of testimonial evidence and the witness' credibility in real-time and, therefore, is deemed to be

[360] *Id.* at 5-33.

[361] *Id.* at 5-39 to 5-41.

reliable means of assessing whether evidence is probative. Here, there is no indication that Barnes' testimony is untruthful or inaccurate. Instead of challenging the veracity of Barnes' testimony, PG&E reiterates its position that it reprioritized the ECDA work to perform pressure tests for TIMP. Accordingly, we find that at least some work was reprioritized from both programs (ECDA and D.11-06-017 compliance). Because PG&E does not provide data for us to quantify exactly how much work was covered by each respective program, we will assign cost responsibility based on the weight of the record evidence.

As noted earlier, TURN's evidence is more probative than PG&E's evidence on this issue; thus, we find that PG&E's shareholders should be assigned 75 percent of the deferred work and ratepayers should be assigned 25 percent. Accordingly, we adopt the revised 2019 expense forecast for ECDA work as stated in Appendix D.

For PG&E's 2019 expense forecast for ICDA work, we agree with Cal Advocates' recommendation and direct PG&E to establish a memorandum account.

#### 8.1.5. Hydrostatic Testing

Hydrostatic tests are performed to evaluate the strength of transmission pipelines. PG&E performs hydrostatic tests to identify manufacturing defects and confirm the integrity of its transmission pipes. For this program, PG&E performs hydrostatic tests pursuant to the following rules and regulations: (1) 49 CFR Part 192, TIMP, and (2) D.11-06-017 and the National Transportation Safety Board's (NTSB) Safety Recommendation P-10-4.29 (D.11-06-017/NTSB).[362] In addition, when pipelines are out of service to accommodate a hydrostatic test,

[362] PG&E Opening Brief at 5-42.

PG&E provides portable LNG gas service to customers (liquified natural gas/compressed natural gas (LNG/CNG) equipment).

To comply with D.11-06-017/NTSB, PG&E estimates that it will need to either replace or perform hydrostatic tests on 37 miles of pipe.[363] PG&E states that pipeline segments that are less than 100 feet are too short for it to perform hydrostatic tests; thus, PG&E plans to replace them. PG&E estimates that it will replace 1.02 miles of pipe.[364]

PG&E's estimate of capital expenditures for replacing pipeline segments in lieu of performing hydrostatic tests is based on the same methodology that it used to estimate capital expenditures for the Pipe Replacement program. To estimate capital expenditures for the Pipe Replacement program, PG&E developed cost two curves using historical replacement cost data from 2013 to 2016. PG&E used the cost curves to calculate the cost for each project based on the pipe length multiplied by the pipe diameter.[365] PG&E's 2019 expense forecast for replacing pipeline segments in lieu of testing is based on the average historical project cost for replacements that are less than 50 feet, which is approximately $0.5 million per project, without escalation.

For performing hydrostatic tests, PG&E's 2019 expense forecast is based on two cost curves that use historical hydrostatic tests cost data from between 2014-2016.[366] PG&E's forecast for capital expenditures is based on an average of

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[363] Exh. PG&E-1 at 5-42.

[364] *Id.* at 5-45.

[365] *Id.* at 5-50, 5-61.

[366] Exh. PG&E-1 at 5-50.

2016 historical project costs, plus escalation. PG&E states that it did not include the cost to perform hydrostatic tests on pipes that were installed after 1955.[367]

PG&E estimates that it will perform 128 miles of TIMP pressure tests to identify manufacturing defects and pipeline cracks caused by corrosion.[368] PG&E's 2019 expenses forecast is based on the average estimate of project costs for the TIMP pressure tests that PG&E plans to perform during the rate case period.

Pursuant to Section 969, the Commission is required to direct PG&E to establish and maintain a balancing account to track TIMP-related expenditures. PG&E states that Section 969 does not specify whether the balancing account must be one-way or two-way. In D.16-06-056, the Commission directed PG&E to establish a memorandum account to track costs associated with any new transmission integrity management statute or rules effective after January 1, 2015. PG&E argues that, in anticipation of prospective rule changes authorized by the PHMSA, it should be permitted to change its one-way balancing account for this program to a two-way balancing account , and it request that the Commission discontinue the memorandum account for this program and replace it with a Tier 3 Advice Letter process.[369] PG&E states that if it "anticipates incurring costs above the total expenses adopted for this program, PG&E proposes to file a Tier 3 Advice letter detailing the additional costs so that the

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[367] *Id.* at 5-52.

[368] *Id.*

[369] PG&E Opening Brief at 5-86 and 5-88.

Commission and parties have an opportunity to review these additional costs."[370]

PG&E's forecasts of the capital expenditures and 2019 expenses for this program are in Tables 21and 22, respectively.

**Table 21— Capital Expenditures for Hydrostatic Testing[371]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Hydrostatic Testing Capital | 75N, 44A | $19,853 | $20,477 | $21,079 |
| 2 | Replace in Lieu of Hydrotest | 75R, 75Q | 26,393 | 27,223 | 28,023 |
| 3 | LNG/CNG | 73D | 3,651 | 3,766 | 3,877 |
| 4 | Total Capital Expenditures | | $49,897 | $51,465 | $52,978 |

**Table 22— Expense Forecast for Hydrostatic Testing[372]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | Hydrostatic Testing (D.11-06-017) | JTC, 34A | $63,120 |
| 2 | Replace in Lieu of Hydrotest | JT6 | 13,446 |
| 3 | TIMP Pressure Tests | HPF, 34A | 56, 961 |
| 4 | LNG/CNG | GMD | 2,775 |
| | Total Expenses | | $136,302 |

#### 8.1.5.1. Intervenors

Cal Advocates argues that PG&E's expense forecasts for the TIMP pressure tests and the pipeline replacements that it will perform in lieu of hydrostatic testing should be adjusted downward. Cal Advocates argues, and Indicated Shippers agrees, that PG&E's expense forecast for replacing pipes in lieu of performing hydrostatic tests is deficient because it only considers the length of

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370 Exh. PG&E-2 at 17B-10.

371 PG&E Opening Brief at 5-43, Table 5-8.

372 PG&E Opening Brief at 5-43, Table 5-7.

the pipe and incorrectly includes two large projects that are outliers.[373] Indicated Shippers argues that the outliers "should not be used as a statistically valid data point in the project forecast costs that have such a massive effect on ratepayers."[374]

As an alternative to PG&E's forecast methodology for the estimating the capital expenditures for replacing pipes in lieu of performing hydrostatic tests, Cal Advocates states that it used a regression model that uses three relevant variables: pipe length and diameter and project duration.[375] Also, Cal Advocates states that its data set includes 378 projects, which includes projects that were completed by other utilities such as Southwest Gas, while PG&E's model uses data from only 121 projects.[376] Cal Advocates argues that using project duration is useful because a longer project duration could result in higher project costs and that PG&E's subject matter experts should have been able to estimate the project duration.[377] Cal Advocates argues that using pipe diameter helps predict the costs of projects and, therefore, should be used in PG&E's forecast.[378]

Cal Advocates argues that PG&E's TIMP expense forecast should be adjusted upward from $64.2 million to $66.8 million.[379] However, Cal Advocates opposes PG&E's proposal for a two-way balancing account for TIMP projects because PG&E has not demonstrated that such account is necessary.

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[373] Cal Advocates Opening Brief at 40; Indicated Shippers Opening Brief at 16.

[374] Indicated Shippers at 19.

[375] Cal Advocates Opening Brief at 40.

[376] *Id.*

[377] *Id.* at 41.

[378] *Id.* at 43.

[379] *Id.* at 45.

Cal Advocates argues that PG&E's concerns about regulatory uncertainty do not warrant a two-way balancing account as utilities are given sufficient time to address new regulatory requirements.[380]

Indicated Shippers argues that PG&E's 2019 expense forecast of $1.64 million per mile to perform hydrostatic tests is overstated as it is "more than twice the forecast" authorized in the 2015 GT&S rate case (*i.e.,* $850,000).[381] Indicated Shippers assert that PG&E's cost curves produce an R-Squared factor of .506 for the shorter projects and .098 for the longer projects. Indicated Shippers assert that an R-Squared value that is closer to zero indicates that there is no relationship in the forecast model; thus, Indicated Shippers argue, because the R-Squared factor for the longer projects is .098, PG&E's model has no relationship between the length of the pipe and cost of the hydrostatic tests.[382]

TURN argues that the Commission should direct PG&E to remove from rate base, cost overruns that PG&E incurred to replace vintage pipes in lieu of performing hydrostatic tests between 2015 and 2018. TURN assert that, in the 2015 GT&S proceeding, the Commission resolved the dispute over the amount that PG&E could spend for the vintage pipe replacement projects by establishing in D.16-06-056 specific base unit costs by project diameter. For example, TURN asserts that D.16-06-056 authorized PG&E to spend $4.51 million, plus escalation, per mile for pipes with a diameter of less than twelve inches.[383] TURN asserts that PG&E was authorized to replace 80 miles between 2015 and 2018 for $570 million, but that PG&E only replaced 46 miles of vintage pipe and spent

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[380] *Id.* at 44.

[381] Indicated Shippers Opening Brief at 16-17.

[382] Indicated Shippers at 17-18.

[383] TURN Opening Brief (citing D16-06-056 at 88).

$635 million. TURN asserts that PG&E's cost overrun equates to an average project cost per mile of $13.8 million, which is 94 percent above the average authorized unit cost.[384]

TURN argues that PG&E has not offered sufficient evidence to demonstrate that the cost overruns are reasonable. TURN argues that PG&E justifies the cost overruns with general assertions, rather than with project specific information. TURN argues that PG&E's general assertions, such as that it experienced delays obtaining permits, do not rise to an extraordinary level such that PG&E could not have foreseen that the event would cause delays.[385] TURN estimates the disallowance by multiplying the authorized rate by the mileage and diameter of pipe that PG&E replaced. Based on that analysis, TURN recommends a downward adjustment to PG&E's rate base of $317 million.[386]

Lastly, CSU and TURN each disagree with PG&E's proposal to make the TIMP balancing account two-way.[387] TURN asserts that, in the 2015 rate case proceeding, the Commission rejected PG&E's identical proposal to implement a two-way balancing account and Tier 3 Advice Letter process. CSU argues that there have been no changes in circumstance since then, and PG&E makes the same arguments here.[388]

TURN assert that, in rejecting PG&E's Tier 3 Advice Letter proposal, the Commission held that such a mechanism for would be inadequate for reviewing the reasonableness of a large tranche of costs and would not encourage the

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[384] *Id.* at 63.

[385] TURN Opening Brief at 68.

[386] *Id.* at 70.

[387] CSU Opening Brief at 10-11; TURN Opening Brief at 161.

[388] *Id.* at 11.

desired cost discipline.[389] To address PG&E's concern regarding its ability to address potential changes in the TIMP regulations, the Commission authorized a memorandum account for this program so that PG&E could recover reasonable costs related to new statute or rules concerning transmission integrity practices. TURN argues that TIMP expenses forecasted for the instant rate case ($240 million) are higher than the capital and expense amounts forecasted in the prior rate case ($170 million).[390]

#### 8.1.5.2. PG&E Response

PG&E disagrees with Cal Advocates' assertion that the outliers should be removed from its 2019 expense forecast for pipe replacements in lieu of hydrostatic tests. PG&E argues that there are also two very low-cost projects in the estimate. PG&E argues that the outliers represent costs that are normal pipe replacements.[391] PG&E argues that the very high-cost projects include replacing pipes in locations that require resources for traffic control and project management and pipes that have a large diameter and, therefore, require more welding work. PG&E states that if the Commission removed both the two highest cost projects and the two lowest cost projects, the average cost per project would be $339,989 (in 2016 dollars, making its 2019 expense forecast $9.2 million.[392]

PG&E argues that its decision to use two factors, pipe length and pipe diameter, to forecast capital expenditures for its pipe replacement programs is reasonable. PG&E disagrees with Cal Advocates' contention that PG&E should

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[389] TURN Opening Brief at 162 (citing D.16-06-056 at 253-254).

[390] TURN Opening Brief at 162.

[391] PG&E Opening Brief at 5-45.

[392] *Id.* at 5-46 to 5-47.

use project duration as a factor in PG&E's pipe replacement forecasts. PG&E argues that project duration can vary significantly and that PG&E cannot estimate all of the various influences on project duration as PG&E does not have control over some of them.[393] PG&E argues that Cal Advocates' use of a static value project duration of 170 days per project in its analysis suggests that it was not able to account for the variety in project durations and that project duration is not a distinguishing factor among projects.[394]

PG&E argues that Cal Advocates' regression analysis is unreliable because it uses inappropriate and incomplete data. PG&E asserts that Cal Advocates uses project cost data from other utilities and that such data does not represent project costs within PG&E's service territory. PG&E argues that, for the project costs that are based on PG&E's projects, Cal Advocates uses cost data from PG&E's compliance reports related to its Pipeline Safety Enhancement Plan (PSEP). PG&E argues that cost data from its PSEP is not appropriate for Cal Advocates' analysis as the data was provided as of the due date for the compliance report and does not include the final cost for some projects.[395]

PG&E disagrees with TURN's contention that PG&E's capital expenditure for replacing vintage pipes between 2015 and 2018 should be removed from rate base. PG&E argues that it submitted a report that provided updates on its progress to the Commission and stakeholders and no one raised a concern. Moreover, PG&E argues, that the cost overruns were justified. First, PG&E asserts that it had to account for additional engineering and construction

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[393] *Id.* at 5-47.

[394] PG&E Opening Brief at 5-48.

[395] *Id.* at 5-48 to 5-49.

activities such as repairing and replacing pipes. Second, PG&E had to account for certain geographical field conditions, such as high-water tables and weak soil conditions. PG&E stated that pipe replacement project R-503, on Line 50A in Gridley, required PG&E to incur unanticipated costs totaling $12.8 million to address groundwater that included the pumping, handling and disposal of approximately 55 million gallons of water.[396]

Third, PG&E states that it encountered delays due to increased permitting requirements and "restricted work hours to avoid road/lane closures during heavy commute hours." Finally, PG&E argues that it encountered schedule constraints for the "[m]anagement of construction schedules to meet schedule commitments," and that operational constraints on its pipeline system caused schedule delays.[397]

PG&E disagrees with the Indicated Shippers' assertion that the cost curves that PG&E uses to forecast 2019 expense for hydrostatic tests are unreliable. First PG&E asserts that the hydrostatic model has two costs curves, based on the length of the project being forecasted, and each cost curve has its own R-Squared value, rather than only one value, as Indicated Shippers asserts. PG&E also argues that the Indicated Shippers' R-Squared value of .11 is inaccurate. Rather, PG&E argues, for the projects that are less than .314 miles, the majority of the hydrostatic projects for this rate case period, the cost curve has an R-Squared

[396] Exh. PG&E-31 at 5-AtchA-15.

[397] *Id.*

value of .506, which is reasonable.[398] For the second cost curve, which is for the projects that over .314 miles, PG&E confirms that the R-Squared value is .098.[399]

Finally, PG&E argues that its request to change the TIMP balancing account to two-way is consistent balancing account treatment for SoCalGas and SDG&E.

#### 8.1.5.3. Discussion

We find that PG&E's 2019 expense forecast for TIMP pressure tests is just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. We find that Cal Advocates' assertion that PG&E's forecast should be adjusted upward is unsupported as Cal Advocates' Opening Brief does not provide a basis for the adjustment.

With respect to the D.11-06-017/NTSB projects, we find that PG&E's 2019 estimate for replacing pipeline segments in lieu of performing hydrostatic tests is just and reasonable, subject to conditions. We agree with Cal Advocates and Indicated Shippers that the forecast should exclude cost data for high-cost projects that are outliers. We find that PG&E has not demonstrated that the outliers are representative of the type of project that it expects to implement during the instant rate case period. We also agree with PG&E's contention that the Commission should exclude the low-cost project outliers. After removing the outliers, the average project cost for the remaining 12 projects is approximately $340,000.[400] If we add the two high-cost outliers,[401] the estimate increases by

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[398] PG&E Opening Brief at 5-54 to 5-55.

[399] *Id.* at 5-55.

[400] The average cost for 12 projects is $340,000. *See* Exh. ORA-05-SA at 52, Workpaper Table 5-12.

approximately $225,542, which is more than half of the average costs of the 12 other projects. Accordingly, we adopt PG&E's 2019 expense forecast for the projects that will replace pipeline segments in lieu of performing hydrostatic tests, subject to removing the high- and low-cost outliers. The revised forecast is in Appendix D.

Regarding the capital costs for pipe replacement projects that PG&E performs in lieu of hydrostatic tests, we find that PG&E's proposal is just and reasonable. While we agree with Cal Advocates' assertion that PG&E's forecast would be improved if it were based on more data, we decline to adopt Cal Advocates' regression analysis. Cal Advocates' model calculates the average cost for projects using project data from other utilities, such as San Diego Gas & Electric Company and Southwest Gas. Using project cost data from other utilities would not provide a reliable cost forecast in this instance because each utility's system is different.[402] As for PG&E's projects, Cal Advocates' model uses cost data on 181 projects from PG&E's PSEP compliance report. Because PG&E asserts that the cost data in the PSEP compliance report is incomplete, we find that Cal Advocates' forecast is unreliable.

For the hydrostatic test forecasts, we find that PG&E's capital expenditure forecast is just and reasonable as PG&E provided enough evidence to

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[401] The two high-cost outliners are: #42584632 for $1,557,853 and #42596038 for $2,276,742. *See* Exh. ORA-05-SA at 52, Workpaper Table 5-12. If we add the lowest-cost outliers, the average project costs decreases the estimate by approximately $44,426. The two low-cost projects are: #42100185 for $37,275 and #42100182 for $20,771. *Id.*

[402] *See generally*, Southern California Gas Company Pipeline Safety Enhancement Plan Project Application, D.19-03-025 at 51-52 (rejecting a proposed forecast because, in part, "no engineering or design comparison was done among the projects to determine whether they are reasonable comparisons to the proposed projects" and that the proposals did not make distinctions as to the "geographic terrain, and urban verse rural, or mixed urban-and-rural" differences)

demonstrate that the forecasts are credible. No party protested the forecast. We also find that PG&E's 2019 expense forecast for hydrostatic testing that it performs for D.11-06-017/NTSB projects is just and reasonable, subject to conditions. PG&E demonstrates cost curve for the projects that are less than .314 miles have a reasonable R-Squared value. However, the cost curve for the longer segments has a .098 R-Square value, and PG&E does not rebut Indicated Shippers' contention that this value is unreasonable.[403] Accordingly, because Indicated Shippers demonstrates that PG&E's forecast is significantly higher than the forecast adopted in the last rate case and the R-Squared factor for cost curves on the longer pipe segments is unreasonably low, we direct PG&E to establish a one-way balancing account for the D.11-06-017/NTSB 2019 expense activities.

In response to TURN's argument that PG&E should remove from rate base cost overruns for pipe replacements that PG&E implemented in lieu of performing hydrostatic tests during 2015 to 2018. We agree that, in D.16-06-056, the Commission established specific unit costs for pipe replacement projects to resolve extensive disputes raised by multiple parties in that proceeding.[404] We also note that the Commission did not establish a memorandum account for these expenditures. As TURN demonstrated, PG&E exceeded the unit costs for the 2015-2018 pipe replacement projects by approximately $300 million.

With one exception, we are not persuaded by PG&E's contention that the cost overruns for the 2015-2018 pipe replacement projects are reasonable. We agree with TURN, that PG&E should have foreseen the possibility of permit delays. Moreover, a permit delay would explain why certain work was not

[403] PG&E Opening Brief at 5-55.

[404] D.16-06-056 at 76-88 (adopting the unit cost set forth in the decision).

performed timely or at all, rather than justify cost overruns. We find that PG&E's justification—that schedule constraints for "[m]management of construction schedules to meet schedule commitments"—is overly vague. And we find that the issue concerning operational constraints on PG&E's gas system is one that was in PG&E's control and, therefore, PG&E, rather than ratepayers, should bear the costs for the related project delays. However, we are persuaded that the water pump issue that PG&E experienced with project R-503 was unforeseeable and a reasonable justification and that PG&E adequately quantified the associated costs.

Accordingly, we direct PG&E to permanently remove from its capital expenditures $317 million, less $12.8 million, the cost for the R-503, and make the appropriate rate base adjustments. To the extent that actual amount of the disallowed cost overruns for this program exceed the estimated costs for 2017 and 2018, PG&E may recover the discrepancy in its next AGT filing.[405] PG&E shall file a report that provides the actual costs for this program from 2015-2017. The adjustments to PG&E's capital expenditures and 2019 expense for this program are in in Appendix D.

With respect to the balancing account for the TIMP program, for the reasons provided in D.16-06-056 and stated here by TURN and CSU, we find that PG&E should continue to maintain a one-way balancing account and memorandum account for the TIMP program. In the prior rate case, the Commission held that a memorandum account was a reasonable mechanism to account for cost overruns associated with unspecified regulatory changes that

[405] PG&E states that portion of the $317 million in cost overruns is an estimate. PG&E Comment to Proposed Decision at 3-9.

could cause TIMP expenditures to exceed the authorized spending limit. We find that this mechanism continues to be a reasonable method for ensuring the PG&E can continue to recover just and reasonable costs that it incurs to comply with unidentified potential regulation changes that could impact the scope of TIMP work during the instant rate case period, particularly given that the amount authorized for TIMP expenses in this proceeding (*i.e.*, $240 million) exceeds the combine amount authorized for both capital and expenses in the prior rate case (*i.e.*, $170 million).[406] Accordingly, we also find the PG&E should continue to maintain the memorandum account and one-way balancing account for this program.

### 8.2. Pipe Replacements

PG&E asserts that 49 CFR Sections 192.711 through 192.717 provide that PG&E may remediate safety and reliability issues with its transmission pipeline by replacing pipe segments.[407] PG&E asserts that steel pipes constructed before the California pipeline laws were enacted in 1961 (vintage pipes) pose safety and reliability risks because they were manufactured and constructed using practices that are outdated. Accordingly, PG&E uses this program to replace vintage pipes and other pipes that have safety or reliability issues. PG&E states that approximately 47 percent of its transmission pipelines are comprised of vintage pipes. Of that amount, 50 miles are at risk of land movement. During the rate case period, PG&E proposes to replace 8.65 miles of vintage pipes that are at risk of land movement. PG&E also plans to continue to replace pipes that are

[406] D.16-06-056 at 252.

[407] PG&E Opening Brief at 5-58.

damaged due to leaks, corrosions, encroachments and other safety and reliability issues.[408]

To forecast 2019 expenses for vintage pipe replacements, PG&E developed a cost curve using historical replacement cost data from 2013 to 2016. PG&E uses the cost curve to calculate the cost for each project based on the length and diameter of the pipe.[409] For other pipeline safety and reliability replacements projects, PG&E forecasts 2019 expenses using the average annual historical cost from 2014 through 2016. To estimate capital expenditures for the Pipe Replacement program, PG&E developed cost two curves using historical replacement cost data from 2013 to 2016. PG&E used the cost curves to calculate the cost for each project based on the pipe length multiplied by the pipe diameter.[410] PG&E's estimate of the allocation of capital and expense for each type of replacement activity is below in Table 23.

**Table 23— Pipeline Safety and Reliability Replacement Categories**[411]

| Line No. | Category | Capital | Expense |
|---|---|---|---|
| 1 | Leaks | 40% | 39% |
| 2 | Dig-ins | 10% | 7% |
| 3 | Corrosion integrity issues | 11% | 3% |
| 4 | Overbuilds/Encroachments | 2% | - |
| 5 | Other Pipeline Safety/Reliability Issues | 36% | 51% |
| 6 | Retirements/Deactivations (Cap Only) | - | - |

PG&E's forecast of the capital expenditures and 2019 expenses for this program are above in Tables 15 and 16, respectively.

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408 *Id.* at 5-54, 5-58 to 5-59.

409 Exh. PG&E-1 at 5-61.

410 Exh. PG&E-1 at 5-50, 5-61.

411 *Id.* at 5-58.

PG&E states that, while the 2015 GT&S rate case authorized it to replace 80 miles of vintage pipes, it has competed 46 miles.[412] PG&E states that it completed fewer miles than authorized because delays with the Commission's final decision on its 2015 GT&S rate case decision required PG&E to delay time-dependent project tasks such as permitting and land acquisition, among other activities, all of which take approximately 24 months to complete. PG&E states that it was still able to guard against hazardous events by performing other mitigation activities, such as its leak survey program.[413]

Cal Advocates argues that the PG&E should use its regression analysis to forecast the capital expenditures for vintage pipe replacements.[414]

We find that PG&E's 2019 expense and capital expenditure forecasts for this program is just and reasonable. PG&E demonstrated that the scope and pace of work for this program are necessary to provide gas transmission services and that its forecast provides a reliable estimate of the costs that it expects to incur during the rate case period. As discussed in section 8.1.5.3, we disagree with Cal Advocates' recommendation to use its regression analysis.

### 8.3. Geo-Hazard Threat Identification and Mitigation

PG&E uses this program to obtain and analyze data on land movements such as soil creep and dormant landslides. PG&E states that such hazards act slowly over time and can cause catastrophic pipeline failures. PG&E estimates that approximately 4,600 miles of pipe on its system are vulnerable to a potential land movement threat.

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412 PG&E Opening Brief at 5-59.

413 Exh. PG&E-1 at 5-60.

414 Cal Advocates Opening Brief at 45.

PG&E estimates that it will expense mitigation activities performed at six sites for each year in the rate case period. To forecast the 2019 expense for this program, PG&E used historical cost combined with vendor quotes. PG&E estimates that it will implement three capital projects for each year in the rate case period. Using the cost of historical projects, PG&E estimates that each capital project will cost $1.4 million.[415] PG&E's 2019 expense forecast for the Geo-Hazard Threat Identification and Mitigation program is $2.8 million, and its forecast for capital expenditures 4.5 million for 2019, $4.6 million for 2020, and $4.8 million for 2021.

#### 8.3.1. Intervenors

Cal Advocates argues that PG&E's forecast for capital expenditures should exclude a high-cost outlier. Cal Advocates asserts that the forecast includes the historical cost for five projects, four have average costs of $19,000 to $116,000 and one costs $6.7 million. Thus, Cal Advocates recommends a capital forecast that excludes the high-cost outlier.[416]

TURN asserts that, in D.16-06-056, the Commission authorized PG&E to spend $31 million to complete 20 geo-hazard mitigation projects, resulting in an average cost of $1.5 million per project; however, PG&E completed only two mitigation projects at a recorded cost of approximately $6.6 million (an average cost of $3.3 million).[417] TURN argues that PG&E has not demonstrated that that the costs in excess of the amount authorized per project should be included in rate base. Accordingly, TURN argues that the Commission should disallow from

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[415] PG&E Opening Brief at 5-62.

[416] Cal Advocates Opening Brief at 45-46.

[417] TURN Opening Brief at 70-71.

rate base $5.3 million dollars, the authorized average cost subtracted from the recorded costs for both projects.[418]

#### 8.3.2. PG&E's Response

PG&E states that the high-cost outliers is the Line 021E project, which required PG&E to replace an 870-foot pipeline to mitigate the effect of a landslide. The 2016 recorded costs for the Line 021E project was $7 million.[419] PG&E argues that the Line 021E project is representative of the many types of capital projects required for this program.[420] Indeed, PG&E states, for the Line 210C project, which PG&E completed after it provided Cal Advocates with the cost data for this program, PG&E spent approximately $4 million.[421] Accordingly, PG&E argues that the Commission should not require it to remove from its forecast the cost data for Line 021E.

PG&E states that it completed fewer geo-hazard capital projects than the amount that D.16-06-056 authorized because the delay in the final decision on its 2015 GT&S rate case application caused it to delay identifying capital projects. PG&E states that it was still able to guard against safety hazards by performing other mitigation activities.[422]

#### 8.3.3. Discussion

We find that PG&E's 2019 expense and capital expenditure forecasts for this program are just and reasonable. PG&E demonstrated that its forecast

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[418] *Id.* at 72.

[419] Exh. PG&E-31 at 5-71.

[420] PG&E Opening Brief at 5-64.

[421] PG&E Opening Brief at 5-64 to 5-65; *see also* Exh. PG&E-31 5-71, Table 5-15, fns (d) and (e).

[422] Exh. PG&E-1 at 5-66.

provides a reliable estimate of the costs that it expects to incur during the rate case period. We disagree with Cal Advocates' recommendation that PG&E should be directed to remove from its 2019 expense forecast the cost for Line 021E. We are persuaded by PG&E's assertion that, given the unique hazards that this program is required to mitigate, there is a reasonable likelihood that PG&E will encounter projects that have a similar scope over the instant rate case period. We also note that PG&E's historical cost data includes five projects; thus, the outliers represent 33 percent of the work that PG&E performed during the prior rate case period. Accordingly, we find that cost for Line 021E was not an outlier and adopt PG&E's expense and capital expenditure forecasts for this program.

We find that while the average cost for projects was $1.5 million, in D.16-06-056, the Commission did not establish a specific unit cost per project. Accordingly, we decline to limit PG&E's recovery to the average authorized cost per project.

### 8.4. Identification and Mitigation Support

PG&E uses this program to perform Root Cause Analysis and Risk Analysis projects. PG&E states that 49 CFR Section 192.617 requires that it perform a root cause analysis when an ECDA is not suitable.[423] Also, 49 CFR Section 192.617 requires that PG&E performs risk analysis activities such as implementing risk analysis algorithms and data and information management procedures to identify threats and assess risks on all pipeline segments located in HCAs.[424]

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[423] Exh. PG&E-1 at 5-73.

[424] PG&E Opening Brief at 5-68.

PG&E forecasts the 2019 expenses for the Root Cause Analysis work using the average historical program costs from 2015 and 2016.[425] PG&E forecasts 2019 expenses for Risk Analysis work using the average program costs from 2015 to 2016 to determine the average annual costs for performing risk assessments. PG&E's 2019 expense forecast for this program is in Table 23.

**Table 24 - Summary of Expenses for Root Cause Analysis and Risk Analysis**[426]
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | RCA | HPT | $ 4,134 |
| 2 | Risk Analysis | HPA, HPE, HPH, HPL, II#, HP#, KEX, KF1 | 10,114 |
| 3 | Total Expenses | | $14,248 |

For the Root Cause Analysis work, TURN argues that PG&E's 2019 expense forecast should include the recorded cost from 2017. TURN argues that the two years chosen by PG&E represent the highest historical costs for the program in six years. TURN argues that since 2015, the costs for Root Cause Analysis work has declined; thus, PG&E's proposal to increase costs by $1.4 million is unreasonable. Moreover, TURN argues that PG&E's forecasted 2019 expense for the cost for Root Cause Analysis work should be the program's 2017 recorded costs. TURN contends that using the last recorded year consistent with GRC decisions D.04-07-022 and D.89-12-057, which provide that "when costs trend in one direction over three or more years, the last recorded years is appropriate for use.[427] TURN argues that because costs have decreased from 2015 to 2017, the forecasted 2019 expenses for this program should be based on

[425] Exh. PG&E-1 at 5-74.

[426] PG&E Opening Brief at 5-68, Table 5-17.

[427] TURN Opening Brief at 74.

2017 recorded cost since the period from January 1, 2015 to December 31, 2017 is three years.[428]

Accordingly, TURN recommends a downward adjustment of $1.4 million to PG&E's 2019 forecast for this program.[429]

PG&E argues that the recorded expenses for the Root Cause Analysis work declines over two years, "between 2015-to 2016 and between 2016 and 2017," rather than three years. PG&E also argues that the costs for this program are significantly variable as the costs are influenced by the issues and incidents that occur in a particular year.[430]

We find that PG&E's forecasts for the Risk Analysis work are just and reasonable. PG&E demonstrates that its forecast provides a reliable estimate of the costs that it expects to incur during the rate case period.

With respect to the Root Cause Analysis work, we agree with TURN that, consistent with prior GRCs, PG&E's forecast should be based on the last recorded year for the risk analysis work, which is 2017. We are not persuaded by PG&E's argument that the program costs have declined over two, rather than three years because TURN demonstrates that the duration of the costs covered a three-year period. However, because PG&E attests that the costs could vary based on the type of issues and incidents identified, we allow PG&E to establish a memorandum account to track costs that exceed the authorized amount.

Accordingly, we adopt the expense forecast for the Root Cause Analysis work as stated in Appendix D.

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[428] TURN Reply Brief at 5-69.

[429] TURN Opening Brief at 75.

[430] PG&E Opening Brief at 5-69.

### 8.5. Emergency Response Programs

PG&E's Emergency Response Programs consist of three sub-programs: Valve Automation, Valve Safety and Reliability, and Public Awareness. PG&E states that, pursuant to 49 CFR Section 192.616, it is required to develop and implement a Public Awareness sub-program that complies with API Recommended Practice 1162, which sets parameters for communicating messages concerning public safety, emergency preparedness, and environmental protection to the public.[431] PG&E forecasts the 2019 expenses of the Public Awareness sub-program by escalating the average historical costs for this program.[432]

For Valve Automation, PG&E states that, pursuant to Section 957, it is required to install automatic shutoff valves on pipelines located in HCAs or active seismic fault zones.[433] Automatic valves shut off the flow of gas from a ruptured pipeline. PG&E used a risk-based approach to identify the pipeline segments that require automatic shut-off values. Based on that approach, PG&E identified 80 pipeline segments located in HCAs and in non-HCA areas that have a significant impact radius. Accordingly, PG&E plans to automate 80 valves during 2019-2021. PG&E used a contractor to develop the capital expenditure and 2019 expense forecasts for the Valve Automation work. PG&E states that the contractor considered the site logistics, and material and labor costs using construction costs from projects completed in 2015 and material costs from projects completed in 2016.[434]

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[431] Exh. PG&E-1 at 5-83.

[432] *Id.* at 5-86.

[433] *Id.* at 5-77.

[434] *Id.* at 5-83.

PG&E states that, pursuant to 49 CFR 192-745 and General Order (GO) 112-F, Section 143.2, PG&E is required to identify and repair or replace valves that are at risk of becoming inoperable or leaking.[435] PG&E's definition of an inoperable valve includes valves that are no longer accessible due to pavement overlay, flooding, or any condition that prevents access to the valve. PG&E's Valve Safety and Reliability Program tracks, prioritizes, and coordinates resources for valve replacements. PG&E's capital expenditure and 2019 expense forecasts for this program are based on the average historical costs for this program over five years.

PG&E's 2019 expense forecast for the Emergency Response Program is in Table 25, and its capital expenditure forecast is in Table 26.

**Table 25 – Summary of Expenses for Emergency Response Programs[436]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | Public Awareness | JT9 | $3.511 |
| 2 | Valves Safety and Reliability | JTR | 864 |
| 3 | PSEP Valve Expense | KE4 | - |
| 4 | Total Expenses | | $4,375 |

**Table 26 –Summary of Capital Expenditures for Emergency Response Programs[437]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Valve Automation | 75I | $29,541 | $33,552 | $30,118 |
| 2 | Valves Safety and Reliability | 75D | 25,869 | 26,682 | 27,466 |
| 3 | PSEP Valve Automation | 2H3 | - | - | - |
| 4 | Total Capital Expenditures | | $55,410 | $60,233 | $57,584 |

[435] *Id.* at 5-87.

[436] PG&E Opening Brief at 5-71, Table 5-19.

[437] *Id.* at 5-71, Table 5-20.

PG&E states that it reprioritized work that the Commission authorized in the 2015 GT&S rate case. PG&E states that for the 2015-2018 period, it was authorized to spend $218 million in capital to complete 160 valves but that it only completed 140 valves for $146 million. PG&E states that that in lieu of completing the 20 additional valves, it redistributed the funds authorized for this program to other programs in the Pipeline Asset Family that were higher risk.[438]

TURN argues that PG&E should use the recorded cost from 2017 to forecast the 2019 expenses for its Public Awareness sub-program. TURN argues that PG&E uses historical costs from 2014-2016 as the basis for its forecasts even though 2014 includes a one-time project that D.16-06-056 ordered PG&E to remove from its forecast in that proceeding.[439] Moreover, TURN argues, the recorded costs for the Public Awareness sub-program has consistently declined during 2015 to 2017. Accordingly, TURN contends that using the last recorded year for this program is consistent with GRC decisions D.04-07-022 and D.89-12-057, which provide that "when costs trend in one direction over three or more years, the last recorded years is appropriate for use."[440] Accordingly, TURN recommends a downward adjustment of $1.8 million to PG&E's 2019 expense forecast for this program.[441]

PG&E argues that the 2017 recorded expenses for the Public Awareness sub-program were not available to it when it filed the instant application. Moreover, PG&E argues, removing from the forecast the outlier project that

[438] Exh. PG&E-1 at 5-82.

[439] PG&E Opening Brief at 76.

[440] TURN Opening Brief at 76.

[441] *Id.* at 76.

PG&E completed 2014 would mean that there is no three-year trend showing a decline in costs for this program.[442]

We find that PG&E's forecasts for the Valve Automation, Valve Safety and Reliability are just and reasonable. PG&E demonstrated that its forecast provides a reliable estimate of the costs that it expects to incur during the rate case period. However, in its next GT&S rate case, PG&E shall update the showing required in D.12-12-030 regarding the latest development on the use of automated shut-off, particular in seismic zones.[443]

With respect to the Public Awareness sub-program, we agree with TURN that, consistent with prior GRCs, PG&E's forecast should be based on the last recorded year for this program, which is $1.8 million. We are not persuaded by PG&E's argument that the forecast in 2014 is relevant as TURN is referring to the three-year trend from 2015-2017.

### 8.6. Class Location Change

Pursuant to 49 CFR Section 192.613, PG&E is required to track population density so that its operations and related facilities align with the appropriate population class.[444] As such, PG&E is required to perform annual class location studies, routine pipeline patrols, and periodic maintenance inspections. PG&E mitigation activities that employ hydrotests are expensed, while the mitigation activities that require pipe replacement are capitalized.[445]

For PG&E's 2019 expenses, the class location study forecast is based on the 2015 program costs and the hydrotest mitigation forecast is based on historical

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[442] PG&E Opening Brief at 5-72.

[443] D.12-12-030 at 77.

[444] PG&E Opening Brief at 5-72 to 5-73; *see also* Exh. PG&E-1 at 5-91 to 5-92.

[445] *Id.* at 5-73; *see also* Exh. PG&E-1 at 5-93.

program costs from 2012 to 2016. PG&E's capital expenditure forecast for pipe replacement mitigation activities is based on historical program costs from 2012 to 2016.[446]

PG&E's capital expenditure and 2019 expense forecasts for the Class Location Change programs are in Tables 27 and 28, respectively.

**Table 27—Capital Expenditures – Class Location Changes[447]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | Class Location -Replacements | 75H | $5,498 | $5,636 | $5,773 |
| 2 | Total Capital Expenditures | | $5,498 | $5,636 | $5,773 |

**Table 28—Summary of Expenses – Class Location Changes[448]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | Class Location Studies | JTQ | $1,656 |
| 2 | Class Location - Hydrotests | JT9 | $525 |
| 3 | Total Expenses | | $2,181 |

#### 8.6.1. Intervenors

TURN argues that PG&E should be required to remove from its 2019 expense forecast certain costs from 2014. TURN argues that, during 2014, PG&E completed two one-time, nonrecurring projects: GT Classification Review and L-131.[449] TURN also recommends that PG&E's forecast should include 2017 recorded costs because it is the most recent historical cost data that is available.

[446] Exh. PG&E-1 at 5-96.

[447] PG&E Opening Brief at 5-73, Table 5-22.

[448] *Id.* at 5-73, Table 5-21.

[449] TURN Opening Brief at 78-79; TURN Reply Brief at 53.

With these changes, TURN argues that PG&E's 2019 expense should be adjusted downward by $1.5 million.[450]

Cal Advocates argues that the replacement capital expenditures should be based on its regression analysis.

### 8.6.2. PG&E's Response

PG&E agrees with TURN's contention that the GT Classification Review project is a one-time, nonrecurring project that should be removed from the five-year historical average used to calculate its 2019 expense forecast for this program.

However, PG&E argues, it disagrees that the L-131 hydrotest mitigation project, should be removed as the project represents work that PG&E could expect to perform in the future.[451] PG&E explains that in the event of a class location change, 49 CFR 192.611 requires that it confirm the Maximum Allowable Operating Pressure of the affected pipeline, a task the PG&E does by performing hydrostatic strength tests similar to the work performed for the L-131 project. Thus, if PG&E is required to perform a class location change during the current rate case period, it will need to perform work that is similar to the L-131 project. PG&E also argues that its forecast should exclude the 2017 recorded costs as this information was not available at the time that PG&E filed the instant application.[452]

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[450] *Id.* at 78-79.

[451] PG&E Opening Brief at 5-74.

[452] PG&E Opening Brief at 5-74 to 5-75.

#### 8.6.3. Discussion

We find that PG&E's 2019 expense forecasts for the class location study and capital expenditures for pipe replacements are just and reasonable. PG&E demonstrated that its forecast provides a reliable estimate of the costs that it expect to incur during the rate case period.

With respect to the 2019 expense forecast for hydrotest mitigation, we agree with TURN's contention that the forecast should include the 2017 recorded costs. We find that, when a program uses historical cost data to forecast future expenditures, the most recent historical data is relevant to generate an accurate forecast of future costs unless such data has one-time, non-recurring projects or activities that cannot be removed. We also agree with TURN's contention that PG&E should remove from its forecasts the cost for the GT Classification Review project. PG&E agrees that, because the GT Classification Review project is a one-time, non-recurring event, GT Classification Review project should be removed from the expense forecast for this program. We find that PG&E has demonstrated that the L-131 project is representative of a project that PG&E could be required to implement during the instant rate case period.

Accordingly, we adopt PG&E's estimated capital forecast for the replacement work and its 2019 expense forecast for the class studies work. For the hydrotest work, we adopt the 2019 expense forecast stated in Appendix D, which is based on the five-year historical cost average from 2013-2017 and excludes the cost of the one-time GT Classification Review project, which was completed in 2014.

### 8.7. Shallow and Exposed Pipe

PG&E is required to meet or exceed the minimum depth of cover requirements for its transmission pipelines.[453] Initial depth of cover may become reduced due to natural forces, such as erosion or stream washouts. PG&E has a land-based portion for this program and a water and levee crossings portion. The land-based portion prioritizes pipeline segments that require the pipe to be reburied or replaced. The water and levee crossings portion is used to organize and catalog relevant information, such as maps and permits.[454]

PG&E has approximately 32.3 miles of pipe that require mitigation. Of the amount at least 4.3 miles have a high risk of failure and will be replaced during the rate case period.[455]

To forecast the capital expenditures and 2019 expenses for the 4.3 miles, PG&E identified the pipe length and diameter for the pipeline segment and then applied that data to the cost calculator that PG&E uses to forecast costs for the Pipe Replacement program.[456]

PG&E's forecast of the capital expenditures and 2019 expenses for this program are above in Tables 15 and 16, respectively.

#### 8.7.1. Intervenors

Cal Advocates argues that for the mitigation activities that require pipe replacements, the capital forecast should be based on the regression model that it

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[453] Exh. PG&E-1 at 5-97.

[454] PG&E Opening Brief at 5-76.

[455] Exh. PG&E-1 at 5-106 to 5-107.

[456] *Id.* at 5-106 to 5-107.

proposed in the section on pipe replacement projects that PG&E plans to implement in lieu of hydrostatic testing.[457]

OSA contends that PG&E does not have specific procedures to identify and mitigate shallow and exposed pipes. OSA asserts that PG&E identifies exposed and shallow pipe only through conducting work for other programs. OSA asserts that for an exposed pipeline segment in the City of Lafayette, PG&E does not have a record of how long the pipeline has been exposed.[458] OSA argues that pursuant to Section 415, utilities are required to ensure the safe operation of gas transmission systems; thus PG&E should be required to develop a plan to ensure that its pipes are adequately covered.[459]

OSA argues that pursuant to Section 961, PG&E is required to inspect and timely repair "other compromised facility conditions," which OSA interprets as including shallow and exposed pipes. However, OSA argues, PG&E dose not explicitly address shallow and exposed pipelines in the Gas Operator's Safety Plan, which PG&E is required to submit pursuant to Section 961. Accordingly, OSA requests that the Commission direct PG&E submit a revised pipeline risk management program procedure so that OSA and others may evaluate PG&E's proposal.[460]

#### 8.7.2. PG&E's Response

PG&E states that, for the exposed pipeline segment in Lafayette (Segment 1), it agrees with OSA's contention that the segment should

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457 Cal Advocates Opening Brief at 47.

458 OSA Opening Brief at 3.

459 *Id.* at 4.

460 *Id.* at 48.

be mitigated during the instant rate case period and plans to complete mitigation work in 2019.[461]

### 8.7.3. Discussion

We find that PG&E's capital expenditure and 2019 expense forecast for the Shallow and Exposed Pipe program is just and reasonable as PG&E provided enough evidence to demonstrate that its forecasts are credible. For the reasons discussed in section 8.1.5.3 on pipe replacements in lieu of performing hydrostatic testing, we decline to adopt Cal Advocates' forecast methodology for the capital expenditures for this program.

We find that OSA's request that the Commission direct PG&E submit a revised pipeline risk management program procedure that explicitly addresses how PG&E will identify and mitigate shallow and exposed pipelines is outside the scope of this proceeding and should be addressed during the Commission Staff's annual audit proceeding.

### 8.8. Work Required by Others (WRO)

The WRO program manages projects that PG&E performs to remove or relocate pipes at the request of third parties. PG&E states that most of the WRO requests are related to public projects, such as improvements to freeways, highways, and city streets. PG&E's capital projects for this program includes relocation work, and its expense projects include mitigation activities such as initial plan reviews and field verifications.[462]

PG&E's capital expenditure and 2019 expense forecasts for this program are based on a three-year historical average from 2013-2015. PG&E states that it

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[461] PG&E Opening Brief at 5-79.

[462] PG&E Opening Brief at 5-80.

removed one large outlier from the forecast. PG&E's 2019 expense forecast for the WRO program is $750,000 and its capital expenditure forecast is $27.9 million for 2019, 28.7 million for 2020, and $29.6 million for 2021. And PG&E proposes to discontinue its Work Required by Others Balancing Account because its forecast is reasonable.[463]

#### 8.8.1. Intervenors

Cal Advocates contends that PG&E's capital expenditure and 2019 expense forecasts should include average cost information from 2016 and 2017. With the additional cost data, Cal Advocates argues that PG&E's 2019 expense forecast should be adjusted downward by $87,000 and that its capital forecast should be adjusted downward by approximately $27.2 million.[464] Cal Advocates states that, if the Commission adopts its proposal, it supports eliminating the one-way-balancing account for this program.[465]

Indicated Shippers argue that PG&E's capital expenditure forecast for this program is overstated. Indicated Shippers assert that the average recorded cost for this program from 2016-2017 is $17 million per year, but in the instant proceeding, PG&E is seeking $27.9 million without providing adequate support for the increase in workload.[466]

#### 8.8.2. PG&E Response

PG&E argues that Cal Advocates and Indicated Shippers have not demonstrated that, for the instant rate case period, PG&E's spending levels will

[463] *Id.* at 16-22.

[464] Cal Advocates Opening Brief at 49.

[465] *Id.* at 50.

[466] Indicated Shippers Opening Brief at 19.

not be consistent with the recorded costs from 2013 through 2015.[467] PG&E contends that the spending levels for this program is "highly variable." Thus, PG&E argues that the Commissions should reject the intervenors' requests for a downward adjustment to its forecasts for this program.

#### 8.8.3. Discussion

We agree with Cal Advocates and Indicated Shippers and find that PG&E's methodology of using three-years of average cost should be based on cost data from 2016 and 2017, rather than cost data from 2013-2015. While PG&E argues that the spending levels for this program are highly variable, we find that such variability would implicate both sets of data. We also find that cost data from 2016 to 2017 would be a more reliable indicator of the WRO for public improvement projects that may occur between 2019 and 2021, rather than cost data from six years ago. Because we find that the adjusted forecast for this program is just and reasonable, we also find that allowing PG&E to discontinue the WRO balancing account is reasonable.

### 8.9. Pipe Investigation and Field Engineering

PG&E states that this program covers common costs for performing various pipeline investigations and repair work that requires field engineering. PG&E states that projects for this program are implemented on an as-needed basis.[468] PG&E's 2019 expense forecast for this program is based on the average three-year historical program costs.[469] PG&E's 2019 expense forecast for the Pipe Investigation and Field Engineering program is in Table 29.

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[467] PG&E Opening Brief at 5-82 to 5-83.

[468] Exh. PG&E-1 at 5-116.

[469] *Id.* at 5-116.

**Table 29 — Expense Forecast for the Pipe Investigation and Field Engineering Program[470] ($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | Pipeline Investigations | JTD | $6,721 |
| 2 | Pipeline Field Engineering | JT1 | $2,018 |
| 3 | Total Expenses | | $8,740 |

TURN argues that PG&E should use a five-year, rather than three-year, historical cost average to forecast the 2019 expenses for the Pipeline Investigation and Field Engineering program.[471] TURN argues that the expenses for this program have fluctuated over the last five years and that the 2016 amount is significantly higher than the other years. Thus, TURN argues, a larger sample size is necessary to flatten the usually high or low years, an approach that is consistent with D.89-12-057 and D.04-07-022, where the Commission held that using an average is appropriate to account for fluctuating costs. Alternatively, TURN argues that PG&E's 3-year forecast should be updated to include recorded costs from 2017. Accordingly, TURN argues that PG&E's forecast should be either adjusted downward by $1.647 million (three-year average from 2015-2017) or $1.15 million (five-year historical cost average from 2013-2017).[472]

PG&E argues that TURN has not presented evidence to demonstrate that the 2016 costs could not be repeated in the future. PG&E also argues that it should not be required to include 2017 expenses in its forecast as the 2017 cost data was not available to PG&E at the time that it filed the instant application.[473]

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[470] PG&E Opening Brief at 5-84, Table 5-28.

[471] TURN Opening Brief at 80.

[472] TURN Opening Brief at 80-81.

[473] PG&E Opening Brief at 5-85.

We agree with TURN's contention that PG&E should use the most recent recorded costs to generate is 2019 expense forecast. We find that using the 2017 recorded costs is reasonable as it is the most recent cost and, therefore, improves the likelihood that PG&E's forecast will be consistent with the costs that it incurs during the rate case period and the rates that will ultimately be charged to ratepayers. Also, we find that using the three-year average of historical costs is not inconsistent with Commission precedent. Accordingly, consistent with the average three-year historical program cost from 2015-2017, PG&E's 2019 expense forecast for this program must be adjusted downward by $1.647 million.

### 8.10. Remaining Programs

#### 8.10.1. Earthquake Fault Crossings

PG&E states that California law requires that it identify and mitigate damages that earthquakes can cause to transmission pipelines.[474] PG&E's Earthquake Fault Crossings program conducts studies of locations where its transmission pipelines cross earthquake fault lines, monitors previous study findings, and mitigates fault-crossing risks.[475]

PG&E estimates that it will perform 17 studies per year.[476] PG&E estimates that it will install monitoring facilities at four sites during the rate case period.

PG&E states that since the last rate case, it has identified 45 percent or 249 more crossings (where pipelines traverse earthquake faults).[477] Based on its risk

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[474] Exh. PG&E-1 at 5-63.

[475] PG&E Opening Brief at 5-11.

[476] Exh. PG&E-1 at 5-66.

[477] *Id.* at 5-64.

analysis, which prioritizes pipelines located in HCAs, PG&E states that plans to conduct approximately 18 mitigations of from 2019-2021.[478]

PG&E forecast costs for this program using the average unit cost for past studies and various mitigation projects such as for pipe replacements. For fault crossing studies, PG&E estimates that it will spend $61,300 per study. PG&E estimates that the cost for site monitoring will be $60,400 per site. PG&E estimates that mitigation will cost $1.9 million per project. PG&E estimates capital expenditures for this program of $12.2 million in 2019, $12.6 million in 2020, and $12.9 in 2021. PG&E's 2019 expense forecast for this program is $1.4 million.

#### 8.10.2. Gas Gathering

In the 1930s, PG&E installed gas gathering pipelines, dehydration stations, and meters to extend its system to individual wells where PG&E purchased production gas at the wellhead.[479] D.89-12-016 encouraged PG&E to divest its gas gathering assets. PG&E now has 103 idle gas gathering meters that should be retired. PG&E estimates that it will retire approximately six idle meters each year of the rate case period. PG&E forecasts the costs for retiring each idle meter using historical expenditures from between 2012 to 2016. Based on that approach, PG&E estimates that it will cost $608,000 to retire each meter.[480]

PG&E's forecast of capital expenditures for this program is $4 million, $4.1 million and $4.2 million for 2019, 2020, and 2021, respectively.[481]

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[478] *Id.* at 5-65.

[479] *Id.* at 5-108.

[480] *Id.* at 5-110.

[481] PG&E Opening Brief at 5-12.

Cal Advocates argues that in the 2015 GT&S rate case, PG&E was authorized to retire nine gas gathering assets but only retired three assets. Accordingly, Cal Advocates argues that the PG&E should file an annual Tier 1 Advice Letter describing the progress of this program, including how many facilities it retired and the associated costs for the retirements.[482]

#### 8.10.3. Discussion

We find that PG&E's forecasts for the Earthquake Fault Crossings and Gas Gathering programs are just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. No party opposes these forecasts. Accordingly, we adopt PG&E's capital expenditure and 2019 expense forecasts for the Earthquake Fault Crossings, and its capital expenditure forecast for the Gas Gathering Program.

We agree with Cal Advocates' recommendation that PG&E should file a Tier 1 advice letter providing a status update of its progress with the Gas Gathering program. PG&E's pace of work for this program is relatively slow, thus further delays would be an unreasonable response to the Commission's directive in D.89-12-016.

## 9. Corrosion Control

PG&E's Corrosion Control programs for transmission pipeline, storage, and facilities, all manage metallic natural gas assets that can be damaged by corrosion. PG&E defines corrosion as "an electrochemical process where metal degrades due to its interaction with the environment."[483] PG&E asserts that 14 percent of all United States onshore natural gas transmission incidents

[482] Cal Advocates Opening Brief at 48.

[483] Exh. PG&E-1 at 8-17.

between 2010 and 2016 are attributed to corrosion.[484] Accordingly, PG&E's Corrosion Control programs identify and mitigate the threat of external and internal corrosion on its transmission pipeline system.

Internal corrosion is the loss of metal on the interior of the pipeline system and is caused by the presence of an electrolyte, such as water. PG&E mitigates internal corrosion by monitoring gas inputs to ensure that electrolytes are not introduced into PG&E's pipeline system.[485] PG&E uses gas treatment facilities to remove electrolytes from natural gas supplies.

External corrosion is the loss of metal on the exterior of the pipeline system. PG&E uses coating systems to isolate the pipe from electrolytes that are present in the area surrounding the pipe. For pipeline segments that cannot be visually inspected because they are buried or submerged, PG&E also uses Cathodic Protection (CP), a process that manipulates the natural corrosion process.[486] PG&E states that, in addition to electrolytes, direct current (DC) and alternating current (AC) sources that are located near pipeline segments can cause corrosion.[487]

PG&E manages corrosion mitigation activities using the following programs: (1) AC Interference, (2) Atmospheric Corrosion, (3) Casings, (4) CP, (5) Close Interval Survey (6) Corrosion Support, (7) DC Interference, (8) Internal Corrosion, (9) Routine Corrosion Maintenance (10) Standard Pacific Gas Line, Inc. (StanPac), and (11) Test Stations.

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[484] PG&E Opening Brief at 8-1.

[485] Exh. PG&E-1 at 8-19.

[486] Exh. PG&E-1 at 8-18.

[487] PG&E Opening Brief at 8-19.

PG&E's capital expenditures and 2019 expense forecasts for this program are in Tables 30 and 31 respectively.

**Table 30 — Corrosion Control Capital Expenditures**[488]

| Line No. | Description | MAT | 2019 Forecast | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | DC Interference | 3K9 | $12,242 | $12,627 | $12,999 |
| 2 | AC Interference | 3K4 | 13,012 | 3,991 | 6,180 |
| 3 | Casings | 3K5 | 24,411 | 22,784 | 17,485 |
| 4 | CP | 3K6, 3K7 | 13,646 | 13,273 | 10,014 |
| 5 | Test Stations | 3K8 | - | - | - |
| 6 | Atmospheric Corrosion | 3KA | 2,803 | 2,891 | 2,976 |
| 7 | Internal Corrosion | 3K1 | 13,012 | 13,421 | 13,816 |
| 8 | StanPac Capital | 44A | 74 | 42 | 43 |
| 9 | Total Capital Expenditures | | $79,201 | $69.028 | $63,513 |

**Table 31 — Summary of Expenses Corrosion Mitigation Activities**[489]
**($ Thousands of Nominal Dollars)**

| Line No. | Description | Maintenance Activity Type (MAT) | 2019 Forecast |
|---|---|---|---|
| 1 | Routine Corrosion Maintenance | JOZ, JOB, JOQ, JOA, JOC, GJL | $2,174 |
| 2 | Direct Current Interference | GJF | 713 |
| 3 | Alternating Current (AC) Interference | GJA | 2,625 |
| 4 | Casings | GJM | 2,057 |
| 5 | Cathodic Protection (CP) | GJC | 4,401 |
| 6 | Test Stations | GJM, GJD | 257 |
| 7 | Atmospheric Corrosion | GJB | 11,501 |
| 8 | Close Interval Survey (CIS) | GJE | 5,476 |
| 9 | Internal Corrosion | GJH | 3,561 |
| 10 | Corrosion Support | GJK | 2,558 |
| 11 | CP Resurvey | GJC | - |
| 12 | GT Mitigate Corrosion Other | GJ# | - |
| 13 | Standard Pacific Gas Line, Inc. (StanPac) Expense | 34A | 376 |
| 14 | Total | | $35,699 |

488 Exh. PG&E-1 at 8-12, Table 8-3.

489 Exh. PG&E-1 at 8-11, Table 8-2.

### 9.1. AC Interference

PG&E states that AC interference can occur when an AC transmission line is located near metallic components of its pipeline system. There are three types of AC Interference: Inductive Coupling,[490] Resistive Coupling,[491] and Captive Coupling.[492] Approximately 35 percent or 3,010 miles of PG&E's natural gas transmission system are located near AC transmission lines.[493] This program has five subprograms, (1) Arc-Fault Investigations, (2) Arc-Fault Mitigations, (3) Induced AC Investigations, (4) Induced AC Mitigation, and (5) AC Coupon Test Stations.

The Arc-Fault Investigation subprogram manages activities necessary for PG&E to comply with 49 CFR § 192, which requires PG&E to protect pipelines from fault currents that occur when gas and electric assets are in close proximity.[494] PG&E's 2019 expense forecast for conducting arc-fault studies is based on PG&E investigating four facilities at a rate of $610 per study. PG&E's 2019 expense forecast for performing engineering evaluations for this sub-program is based on PG&E evaluating 1,000 poles and tower locations at a unit cost derived from contractor estimates for comparable work.[495]

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[490] Inductive Coupling occurs when pipelines receive AC voltages and related currents from the electromagnetic field that is generated from electricity flowing on AC transmission lines. *See* Exh. PG&E-1 at 8-AtchA-1.

[491] Resistive Coupling occurs when AC current travels to the ground due to abnormal operations or faults, such as when the transmission network is damaged and lightning strikes wires, poles, or towers. *See* Exh. PG&E-1 at 8-AtchA-3.

[492] Captive Coupling is a form of Inductive Coupling, but the electric energy from electromagnetic field has no path-to-ground and is therefore stored in the pipeline.

[493] PG&E Opening Brief at 8-21.

[494] *Id.* at 8-22.

[495] Exh. PG&E-1 at 8-38.

The Arc-Fault Mitigation subprogram manages mitigation activities for poles and towers, and electric substations. PG&E estimates that 31 areas on its pipeline system have poles and towers that require mitigation work, such as enhancing and installing grounding systems.[496] For substation mitigations, PG&E plans to relocate the gas transmission pipeline segments installed in all its electric facilities. Over the instant rate case period, PG&E plans to relocate gas transmission pipes for two substations.[497] PG&E's 2019 expense forecast for mitigating its towers and poles is based on the average cost of five prior mitigations that PG&E has completed.[498] PG&E's capital expenditure forecast for mitigating substations is based on the historical forecast of performing similar work, adjusted down by approximately 65 percent to account for the differences in station size and pipe diameter.[499]

PG&E plans to conduct Induced AC Investigations at five locations in 2019. PG&E 2019 expense forecast for this subprogram is based on a contractor estimate for performing an Induced AC study of Line 191, which is 17.7 miles.[500] PG&E estimates that the results from its Induced AC Investigations sub-program determines the scope of work for its Induced AC Mitigation subprogram. PG&E estimates that it will perform capital projects to mitigate eight locations and 54 grounding cells in 2019. In 2020, PG&E estimates that it will mitigate three locations and 19 grounding cells, and in 2021, it will mitigate 10 grounding

[496] Exh. PG&E-1 at 8-37.

[497] *Id.*

[498] *Id.* at 8-38.

[499] *Id.* at 8-39.

[500] *Id.*

cells.[501] PG&E's capital expenditure forecast for this subprogram is based on the cost of a completed zinc ribbon (a CP technique) installation.[502]

PG&E's AC Coupon Test Station subprogram monitors the AC densities, Inducted AC voltage on the pipeline, and AC corrosion rates. PG&E plans to install 10 AC coupon test stations each year of the rate case period. PG&E's capital expenditure forecast for this subprogram is based on the average cost of completed test station installations from 2012-2016.[503]

PG&E 2019 expense forecasts for AC Interference Program is $2.6 million, and its 2019 capital expenditure forecast is $13 million.[504]

#### 9.1.1. Intervenors

Cal Advocates argues that PG&E's expense forecast for the AC Interference program should be based on the program's three-year average recorded costs from 2015-2017. Using this methodology, Cal Advocates argues, PG&E's 2019 expense forecast should be $1.55 million, instead of $2.6 million.[505] Cal Advocates disagrees with PG&E's assertion that Cal Advocates' forecast will not provide sufficient funding for PG&E to maintain compliance with minimum pipeline safety regulations. Cal Advocates argues that the only safety regulation that applies to this area is 49 CFR § 192, and that regulation does not identify a minimum requirement nor set a standard of work that PG&E must meet in this rate case. Thus, Cal Advocates argues that "PG&E should be discouraged from

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[501] *Id.* at 8-37.

[502] *Id.* at 8-39.

[503] Exh. PG&E-1 at 8-39.

[504] PG&E Opening Brief at 8-21.

[505] Cal Advocates Opening Brief at 74-75.

making false assertions of non-compliance with the law by rejecting the forecast it has made for AC Interference on such basis."[506]

With respect to PG&E's capital forecast for this program, Cal Advocates asserts that PG&E has consistently recorded fewer capital expenditures than the authorized amount. For example, Cal Advocates asserts that for 2016, PG&E forecasted $10.4 million in capital expenditures but only recorded $1.8 million. Cal Advocates argues that PG&E has not demonstrated that the forecasting error from 2016 has been resolved with the 2019 forecast, which is 762 percent higher than PG&E's 2016 recorded costs.[507] Cal Advocates argues that PG&E may be planning to use the excess funding to mitigate pipeline segments that are out of compliance.[508] Accordingly, Cal Advocates argues that PG&E's capital expenditure forecast for this program should be $8.55 million, based on PG&E's historical expenditures.[509]

#### 9.1.2. PG&E Response

PG&E argues that, in its testimony, it asserted that the work covered by its 2019 expense forecast is not only to perform compliance activities, as Cal Advocates asserts, but also to implement "industry best practices [] and adequately mitigate health and safety hazards and pipeline integrity threats."[510] PG&E argues that 49 CFR § 192 requires it to maintain a program to minimize the detrimental impacts that "stray currents" could have on its system.[511] PG&E

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[506] *Id.* at 75.

[507] Cal Advocates Opening Brief at 75.

[508] *Id.* at 75.

[509] *Id.* at 75.

[510] PG&E Reply Brief at 8-6 (citing Exh. PG&E-31, at 8-17, Lines 6-9).

[511] *Id.* at 8-7.

reiterates that it has over 3,000 pipeline locations that require mitigation as they are located in areas susceptible to fault currents. PG&E asserts that even though Cal Advocates challenges the veracity of PG&E's testimony, Cal Advocates did not cross-examine PG&E's witness for this program at the hearing.[512]

PG&E argues that using Cal Advocates' three-year historical average as the capital forecast would underfund this program. PG&E states that in 2016 it expanded the scope of the program to include electric stations; therefore, the historical average will not account for performing arc-fault mitigation activities at two stations.[513] Also, PG&E argues that the scope of work for the 2015-2017 forecast only included five pilot programs, while the instant forecast supports implementing the full mitigation program.[514]

#### 9.1.3. Discussion

We find that PG&E's forecast for the AC Interference program is just and reasonable, subject to conditions. We find that PG&E has demonstrated that the estimated scope work and related expenditures for the AC Interference sub-programs are credible. We disagree with Cal Advocates' contention that PG&E should use the historical average program cost to estimate the capital expenditures for this program as PG&E has expanded the scope for this program such that the prior historical cost data will not generate an accurate forecast. However, we are concerned that, similar to its performance in 2016, PG&E may not complete the forecasted work for this program. Thus, we direct PG&E to

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[512] *Id.* at 8-8.

[513] PG&E estimates that the total costs to mitigate the two stations will be $3.976 million. PG&E Opening Brief at 75.

[514] PG&E Opening Brief at 8-25.

establish a one-way balancing account to record the capital expenditures for this program.

With respect to PG&E's 2019 expense forecast for this program, we disagree with Cal Advocates' contention that the forecast should be reduced. PG&E's AC Interference program is comprised of several sub-programs for which PG&E has estimated the pace of work and related costs. Cal Advocates does not challenge PG&E's estimates for any of PG&E's sub-programs. Instead, Cal Advocates avers that PG&E justifies its forecast by asserting that its forecasted expenses are necessary for the sole purpose of complying with a statute that does not set forth a specific pace of work. However, PG&E does not make that claim and demonstrates that Cal Advocates overlooked the other reasons that PG&E asserted as justifications for its forecasted expenses. Accordingly, we find that PG&E's evidence supporting this program is credible and that its forecast methodology is reasonable.

### 9.2. Atmospheric Corrosion

PG&E states that elements in the atmosphere can cause exposed steel pipeline segments to corrode. The Atmospheric Corrosion program manages activities that (1) monitor atmospheric corrosion on PG&E's pipeline and (2) remediate identified corrosion by replacing or repairing the affected pipeline segments.[515] PG&E states that repairing and maintaining the pipelines typically involves re-painting the asset where the protective coating has failed.

As part of PG&E's Atmospheric Corrosion Program, PG&E inspects exposed assets every three calendar years, not to exceed 39 months.[516] PG&E

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[515] PG&E Opening Brief at 8-4.

[516] Exh. PG&E-1 at 8-56.

estimates that, during the rate case period, it will need to inspect 5 percent of the total population of piping, such as spans that cross gorges.[517] PG&E developed a unit cost for the inspection work using contractor invoices for previous inspections, plus the cost of engineering resources, data analysis, and program management.

For its 2019 expense forecast for this program, PG&E estimates that it will repair 3.4 percent of the spans and electrical stations that will be inspected during the rate case period.[518] PG&E determined that the life for its atmospheric coating system is 30 years, thus it estimates that it will implement 22 expense activities to recoat spans.[519] PG&E calculated the unit cost for repairing the spans using the average historical cost of repair work completed between 2015 and 2017. For repairing the electric stations, PG&E calculated the unit cost by averaging historical costs of repair work completed between 2012 and 2014, the time period in which most of the cost data is available.[520]

PG&E's capital expenditure forecast is based on the average life span of its atmospheric corrosion coating system (30 years) divided by the number of spans that PG&E plans to upgrade.

PG&E 2019 expense forecasts for the Atmospheric Corrosion program is $11.5 million, and its capital expenditure forecast is $2.8 million for 2019, $2.9 million for 2020, and $3.0 million for 2021.[521]

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[517] *Id.* at 8-55.

[518] Exh. PG&E-1 at 8-57.

[519] PG&E states that the pace of work for capital projects is calculated by dividing 30 years by 250 spans. Exh. PG&E-1 at 8-58.

[520] Exh. PG&E-1 at 8-57.

[521] PG&E Opening Brief at 8-5.

#### 9.2.1. Intervenors

TURN argues that PG&E's expense forecast for this program should be reduced to $2 million, the average recorded costs for this program, because PG&E has consistently underspent for this program from 2015-2017. TURN states that PG&E justifies the 2017 forecast discrepancy by attesting that it "revised the repair procedure for these assets and reduced the scope from full recoats to spot repairs, significantly reducing the cost of span and exposed asset repair."[522] Thus, TURN argues, the cost savings from the revised procedure should be reflected in the forecast for the instant rate case.

#### 9.2.2. PG&E Response

PG&E disagrees with TURN's suggestion to use the average recorded costs from 2015-2017 to determine PG&E's 2019 expense forecast. PG&E asserts that, unlike the 2015 rate case period, over the instant rate case period it plans to "proactively re-coat aged coating systems, while upgrading pipeline span foundations and supports."[523]

PG&E explains that the historical underspending for this program was due to it having to remediate fewer spans over the 2015 rate case period than it originally estimated and because it excluded from its forecast backlogged compliance work, for which its shareholders paid $29.6 million to fund atmospheric corrosion mitigation work.[524] PG&E asserts that its 2019 forecast addresses these issues and is reasoanble.

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[522] TURN Opening Brief at 129 (citing PG&E Response to TURN Data Request 16-13.a).

[523] PG&E Opening Brief at 8-33.

[524] *Id.* at 8-34.

#### 9.2.3. Discussion

We find that PG&E's capital expenditure and 2019 expense forecasts are just and reasonable, subject to conditions concerning PG&E's expense forecast. We find that PG&E has demonstrated that the scope of work for the instant rate case period will be more extensive than the work estimated for the prior rate case period; thus, we disagree with TURN's recommendation to reduce PG&E's expense forecast using average historical recorded costs.

However, we recognize that PG&E's historical underspending for this program is concerning. As TURN demonstrates, PG&E's historical underspending for the expense activities for this program from 2017-2018 is approximately $50 million, and PG&E admits that it overestimated its prior forecast. Accordingly, we find that PG&E's 2019 expense forecast should be adjusted downward to reflect the average recorded cost from 2015-2017, which is $2 million per year. We also direct PG&E to maintain a one-way balancing account for the expense activities for the Atmospheric Corrosion program.

### 9.3. Casings

PG&E states that casings are no longer deemed necessary to protect steel pipe from external stress caused by above-ground railroad and street crossings.[525] However, pursuant to 49 CFR § 192, PG&E is required to "verify electrical isolation," because the loss of electrical isolation between a casing and a steel pile can cause external corrosion.[526] Thus, PG&E monitors its cased crossings.[527] For the approximately 530 cased crossings that are not equipped

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[525] PG&E Opening Brief at 8-26.

[526] Exh. PG&E-1 at 8-42.

[527] *Id.*

with "test leads," PG&E uses alternate testing methodologies, except for the 25 locations that cannot be remediated.[528]

During the instant rate case period, PG&E plans to replace the 25 cased crossings that cannot be remediated.[529] PG&E forecasts capital expenditures for this program using the methodology used for its Pipe Replacements program.[530] PG&E's 2019 expense forecast is based on a variety of activities. First, to estimate the cost of performing bi-weekly leak surveys at 10 cased crossings, PG&E used the unit costs from prior leak surveys. Second, PG&E estimates the cost to remediate two case crossings using the average historical unit costs from 2012-2017. Third, to estimate the cost to installing a new test lead on a cased crossing, PG&E used the average cost for completing similar projects.[531] Lastly, to estimate the cost for monitoring 490 cased crossings that do not have test leads, PG&E uses the average cost of projects implemented in 2017.[532]

PG&E 2019 expense forecasts for the Casings program is $2.1 million,[533] and its capital expenditure forecast is $24.4 million for 2019, $22.8 million for 2020, and $17.5 million for 2021.[534]

#### 9.3.1. Intervenors

Cal Advocates argues that PG&E's 2019 capital expenditure forecast should be $15.7 million, the historical average of recorded capital expenditures

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[528] Exh. PG&E-1 at 8-43 and 8-44; PG&E Opening Brief at 8-28.

[529] *Id.*

[530] *Id.* at 4-46.

[531] *Id.* at 8-45.

[532] *Id.* at 8-46.

[533] PG&E Opening Brief at 8-6.

[534] PG&E Opening Brief at 8-28.

for this program between 2015-2017. Cal Advocates asserts that the fact that its estimate does not include pipe replacements is offset by the other activities that PG&E performed during 2015-2017 but will not perform during the instant rate case period.[535]

TURN asserts that during discovery, PG&E admitted that 12 of the 25 forecasted projects to replace cased crossing were no longer required and that it had identified another project.[536] Subsequently, TURN states that PG&E asserted that it identified six cased crossings that would need to be replaced, but that GHG did not provide supporting documentation. Thus, TURN argues that PG&E's pace of work and related forecast should be reduced by 44 percent to reflect that PG&E will complete 14 replacement projects over the rate case period.[537]

#### 9.3.2. Discussion

We find that PG&E's capital expenditure and 2019 expense forecasts are just and reasonable as PG&E demonstrated that the estimated scope work and related expenditures for this program are credible. We disagree with Cal Advocates' contention that PG&E's capital forecast should be based on the average historical program cost from 2015-2017. As PG&E stated, during 2015-2017, it did not forecast for nor perform pipe replacements at cased crossings; accordingly, the historical cost data is not representative of the capital expenditures that PG&E will incur during the instant rate case period.

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[535] Cal Advocates Opening Brief at 75-76.

[536] TURN Opening Brief at 123-125.

[537] *Id.* at 124-125.

We also disagree with TURN's contention that PG&E should reduce the pace of work for the capital projects. PG&E anticipates that, after it attempts to remediate 69 cased crossings, it will be required to replace at least five pipeline segments, raising the current total to 25, PG&E's forecasted pace of work. No party disputes that PG&E's estimate that seven percent of the total amount of remaining remediation projects could require five pipe replacements. However, because of the forecast discrepancies raided by TURN, we also establish a one-way balancing account for this program.

### 9.4. DC Interference

DC interference occurs when DC currents in the earth use buried metallic pipeline components as an electric circuit and, in doing so, decease the width of such components. The program manages two types of DC interference: static interference and dynamic interference. Static interference occurs when pipelines are located near CP systems owned by third-parties and dynamic interference occurs when a pipeline segment is located near DC -powered mass transit systems.[538] For example, a typical Bay Area Rapid Transit (BART) train requires 800 amperes of DC current, and discharging only one ampere from a pipeline can dissolve approximately 21 points of metal per year.[539]

To address dynamic DC interference, PG&E performed a risk management assessment and assigned priorities to pipeline segments based on their proximity to mass transit systems, such as BART.[540] Further, PG&E developed a program to proactively monitor and mitigate the threat of DC interference in highly

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[538] Exh. PG&E-1 at 8-28.

[539] *Id.* at 8-32.

[540] *Id.* at 8-28.

populated areas.[541] PG&E routinely monitors static interference and mitigates it by balancing CP levels on impacted pipelines or by installing mitigation systems.[542]

During the rate case period, PG&E plans to install test stations at half mile intervals from the DC mass transit system railways and stations, starting from the highest priority area to the lowest.[543] At each test station, PG&E plans to install remote monitoring units so that it can perform real-time monitoring of potential DC interference. PG&E also plans to install DC mitigation systems, along mass transit corridors, to designate safe paths for DC currents.[544]

PG&E developed its 2019 expense forecast for this program using the average historical DC interference expenses from 2015 and 2016.[545] PG&E's capital expenditure forecast is based on historical program cost data.[546] Accordingly, PG&E's 2019 expense forecast for this program is $713,000, and its capital expenditure forecast is $12.2 million for 2019, $12.6 million for 2020, and $12.9 million for 2021.[547]

#### 9.4.1. Intervenors

Cal Advocates argues that PG&E's capital forecast should be reduced by 50 percent. Cal Advocates asserts that from 2013 to 2017, PG&E only recorded $2.5 million in capital expenditures for this program. Cal Advocates argues that

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[541] PG&E Opening Brief at 8-16.

[542] Exh. PG&E-1 at 8-34 to 8-35.

[543] *Id.* at 8-32; PG&E Opening Brief at 8-17.

[544] *Id.* at 8-32.

[545] *Id.* at 8-35.

[546] *Id.* at 8-35.

[547] PG&E Opening Brief at 1-13; Exh. PG&E-1 at 8-35.

PG&E's justification for increasing its capital expenditures for this program—that it is moving from a reactive program to a proactive program—is insufficient.[548] Moreover, Cal Advocates argues, PG&E has not identified a new threat, which is necessary to justify the increase, particularly given that PG&E will be able to rely on remote devices, rather than physical inspections, to monitor DC interference.[549] Accordingly, Cal Advocates argues that PG&E has not met its burden to demonstrate that its forecast is justified.

TURN contends that PG&E is seeking a substantial increase from the prior rate case, from $1.2 million to $12.2 million, to perform work that, to a certain extent, can be deferred to the next rate case cycle. TURN asserts that, for the Dynamic DC Interference work, PG&E identified five priorities, with one being the highest as it represents an "immediate safety hazard."[550] TURN asserts that PG&E intends to perform work assigned to all five priorities during the rate case but argues that PG&E should only remediate the highest priority projects. TURN admits that PG&E's RIBA analysis assigns the same high-risk score for all five priority levels.[551]

#### 9.4.2. PG&E Response

PG&E argues that its testimony adequately demonstrates that, based on its analysis of 2015 in-line inspection data and DC interference investigations, pipeline segments located in close proximity to mass transit systems could be damaged by DC interference. PG&E states that the DC Interface projects that are

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[548] Cal Advocates Opening Brief at 72-73.

[549] *Id.* at 72.

[550] TURN Opening Brief at 117-120.

[551] *Id.* at 213.

assigned a priority level of four are located within two miles of BART transit systems.[552] Thus, PG&E argues that the pace of work and related spending forecast that it proposes to proactively identify and mitigate the risk that DC interference poses to its pipelines is justified.[553]

### 9.4.3. Discussion

We find that PG&E's expense and capital forecast for the DC Interference program is just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. While PG&E has classified the DC Interference work into five priorities, with the first representing work that is an immediate hazard, PG&E has demonstrated that all levels of this monitoring and mitigation work is warranted during the rate case period. We disagree with Cal Advocates' recommendation that PG&E's capital forecast should be reduced by 50 percent. PG&E has demonstrated that it revised the scope of this program since filing its 2015 rate case application. Thus, the related spending for this program should be consistent with the program's new scope of work.

### 9.5. Internal Corrosion

Internal corrosion is caused by the introduction of "corrodants," such as water, into the metallic components of PG&E's pipelines.[554] Pursuant to Subpart I of 49 CFR § 192, PG&E is required to monitor internal corrosion in areas where potently corrosive gas is transported.[555] To limit the potential for internal corrosion, PG&E monitors and enforces natural gas project quality

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552 PG&E Opening Brief at 8-19.

553 PG&E Reply Brief at 8-4 to 8-5.

554 PG&E Opening Brief at 8-38.

555 Exh. PG&E-1 at 8-61.

requirements that limit the level of gas constitutes, such as oxygen, hydrogen sulfide, and chloride, that can be introduced into its pipeline system.

In 2019, PG&E plans to conduct one in-line cleaning, which removes liquid and solid corrodents that were introduced into the PG&E's pipeline system. PG&E also plans to examine six of its filter separators in 2019. PG&E's expense forecast is based on the historical costs of projects over a variety of time periods that most accurately reflects the relevant scope of work planned for the instant rate case period.[556]

This program also manages maintenance and replacement projects for drips, which are pressurized pipeline components designed to collect and remove liquids from pipelines.[557] PG&E states that the "stacked configuration of pipeline drips (drip under mainline piping) does not readily-allow for internal corrosion monitoring," and that many drips are susceptible to corrosion because they were constructed using the seam welding techniques.[558] Accordingly, PG&E plans to perform drip replacements pursuant to its ongoing Drip Sampling Program.[559] PG&E's capital forecast for the replacement projects is based on the methodology that its used to forecast capital expenditures for its Pipeline Replacements program.[560]

In addition, PG&E plans to monitor the presence of liquids at 80 internal corrosion monitoring devices, six filter separators, 351 annual drips, 90 bi-monthly drips, and 70 monitoring points. PG&E states that the scope of

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[556] *Id.* at 8-64 to 8-65.

[557] PG&E Opening Brief at 8-40.

[558] PG&E Opening Brief at 8-40.

[559] *Id.* at 8-41.

[560] Exh. PG&E-1 at 8-65.

work excludes facilities at the Pleasant Creek and McDonald Island storage locations as it intends to decommission or sell these assets during the rate case period.[561] PG&E's expense forecast is based a unit cost that it developed based on estimates of personnel time, chemical analysis, and replacements that will be required for each inspection.[562]

PG&E's 2019 expense forecast for the Internal Corrosion program is $3.56 million, and its forecast for capital expenditures is $13 million for 2019, $13.4 million for 2020, and $13.8 million for 2021.[563]

#### 9.5.1. Intervenors

Cal Advocates asserts that PG&E has historically underspent for this program. Thus, Cal Advocates argues that PG&E's 2019 expense forecast should be reduced to $1.43 million, based on the three-year average of recorded costs from 2015-2017.[564] Similarly, Cal Advocates argues that PG&E's capital expenditure forecast should be reduced. Cal Advocates disagrees with PG&E's contention that its capital forecast accounts for enhanced methodologies outlined in API 1171 as that justification does not appear in PG&E's direct testimony. Moreover, Cal Advocates argues, the applicable sections of API 1171 are not mandatory and, because such sections were effective prior to the last rate case, using historical costs from 2015-2017 should adequately incorporate the associated compliance costs.[565]

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561 *Id.* at 8-65.

562 *Id.* at 8-65.

563 PG&E Opening Brief at 8-66.

564 Cal Advocates Brief at 78.

565 *Id.* at 79.

TURN argues that PG&E's forecasted pace of work for performing drip replacements should be reduced to 10 projects because PG&E has not demonstrated that 15 projects are warranted.[566] TURN asserts that PG&E's drip replacement program is new and that PG&E's direct and rebuttal testimony and workpapers do not identify specific areas on its pipeline system that require drip replacements. Thus, TURN argues that reducing PG&E's pace of work by one-third is reasonable as it would allow PG&E to gain an understanding of the extent to which internal corrosion is affecting its drip components.[567]

#### 9.5.2. PG&E Response

PG&E argues that Cal Advocates' recommendation should be rejected because its alternate expense forecast does not account for the program changes that PG&E must implement to comply with the API 1171 and the new DOGGR regulations. Further PG&E argues that Cal Advocates' recommendation does not include a cost escalation factor.[568] PG&E argues that its workpapers include detailed cost estimates for the pace of work for this program.[569]

PG&E argues that its testimony did in fact mention that it would incorporate the relevant sections of API 1171 into this program. PG&E states that it referred to incorporating API 1171 in a separate section of its testimony discussing a summary of changes since the 2015 GT&S case, and PG&E asserts that it was unnecessary to restate that information in the instant section.[570] PG&E argues that Cal Advocates' argument that API 1171 is not mandatory is

566 TURN Opening Brief at 132.

567 *Id.* at 133.

568 PG&E Opening Brief at 8-41.

569 PG&E Reply Brief at 8-18 (citing Exh. PG&E-9, WP 8-56).

570 *Id.* at 8-18.

inapposite to its argument that PG&E should have implemented compliance activities during the last rate case.[571]

PG&E disagrees with TURN's contention that PG&E should reduce the scope of work for the drip replacement capital projects. PG&E asserts that of the 136 drips components on its backbone transmission system, it plans to replace 15 (or 11 percent) to evaluate the threat that DC interference poses to drip components across its entire gas pipeline system. PG&E argues that TURN has not provided evidence demonstrating that this pace of work, which PG&E's Chief Corrosion Engineer recommended, should be reduced.[572]

#### 9.5.3. Discussion

We find that PG&E's capital and expense forecast for this program is just and reasonable, subject to conditions. PG&E's testimony and workpapers adequately describe the scope of work and estimated costs for each component of its expense forecast. Accordingly, we decline Cal Advocates' request to adjust PG&E's 2019 expense forecast downward.

With respect to PG&E's capital forecast, we disagree with TURN's recommendation to reduce PG&E's pace of work for the drip replacement program. We find PG&E's Chief Corrosion Engineer's recommendation to test 11 percent of the drip components on PG&E's backbone system reasonable. However, we also find that PG&E does not explain with adequate detail its methodology for calculating its capital forecast. Accordingly, we direct PG&E to establish a one-way balancing account for the capital expenditures for this program.

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[571] *Id.* at 8-20.

[572] PG&E Opening Brief at 8-43.

### 9.6. Routine Corrosion Maintenance

PG&E uses this program to manage activities for monitoring corrosion and maintaining compliance with relevant regulations. Pursuant to 49 CFR § 192.467, PG&E is required to annually test each pipeline that uses CP; thus, PG&E plans to perform annual CP monitoring on 6,700 test stations and 2,800 cased crossings.[573] Pursuant to 49 CFR § 465(d), PG&E is required to investigate and troubleshoot CP levels that are below a certain range. For pipelines that have a low CP level, PG&E must perform corrective maintenance. Pursuant to 49 CFR § 192.481(a), PG&E is required to inspect all metallic gas piping exposed to the atmosphere to determine whether the pipes have signs of corrosion.[574] PG&E estimated the 2019 expenses required for these activities using historical cost data for each respective activity.[575] PG&E's 2019 expense forecast for this program is $2.2 million.[576]

Cal Advocates asserts that PG&E's 2019 expense forecast is higher than its recorded expense from prior years such as 2016, which was $1.44 million. Thus, Cal Advocates recommends that PG&E reduce its forecast to $1.49 million, based on the three-year historical average of recorded costs for this program.[577]

PG&E argues that Cal Advocates' recommendation would prevent PG&E from performing mandatory work in 2019 as follows: 28 atmospheric inspections, 3,100 CP reads, and 299 rectifier inspections.[578] Accordingly, PG&E

[573] Exh. PG&E-1 at 8-24.

[574] Exh. PG&E-1 at 8-25.

[575] *Id.* at 8-27.

[576] PG&E Opening Brief at 8-10.

[577] Cal Advocates Opening Brief at 71.

[578] PG&E Opening Brief at 8-11.

request that the Commission decline to adopt Cal Advocates' proposed forecast adjustment.

We find that PG&E's expense forecast for the Routine Corrosion program is just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. PG&E asserts that its forecasted pace of work is necessary to comply with the relevant sections of 49 CFR § 192. Cal Advocates does not dispute the scope of PG&E's pace of work or offer an alternative schedule for PG&E to comply with the relevant sections of 49 CFR § 192. Thus, we decline Cal Advocates' recommendation to adopt a forecast that is based solely on the historical average of recorded program costs as PG&E has demonstrated that amount does not reflect that funding necessary for PG&E to complete the compliance-related work.

### 9.7. Remaining Programs

#### 9.7.1. Cathodic Protection

This program manages capital projects that replace CP system components and install new CP systems.[579] PG&E plans to install 60 groundbeds for new CP systems and to replace 10 groundbeds per year.[580] PG&E also plans to replace 10 rectifiers per year.[581] PG&E forecasts capital expenditures for replacing groundbeds and rectifiers using the historical costs for the respective projects between 2012 and 2017.[582]

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579 PG&E Opening Brief at 8-4.

580 Exh. PG&E-1 at 8-50.

581 *Id.* at 8-52.

582 Exh. PG&E-1 at 8-52.

PG&E also uses this program to implement enhanced CP criteria, network services for remote monitoring units, and other CP components.[583] PG&E plans to complete the field investigations, engineering and design for approximately 875 miles of pipeline by the end of 2021.[584] To forecast 2019 expenses, PG&E uses cost data from current contracts and historical costs.

PG&E's 2019 expense forecast for the CP program is $4.4 million, and its forecast for capital expenditures is $13.6 million for 2019, $13.3 million for 2020, and $10 million for 2021.[585]

#### 9.7.2. Close Interval Survey

PG&E uses this program to monitor external corrosion on its pipeline system. PG&E surveys the CP levels between test points and compares that result with the readings obtained at test stations through its system. PG&E plans to perform surveys on 6,000 miles of transmission pipe over 15 years. During the rate case period, PG&E plans to survey 450 miles of pipe per year.[586] When the survey reveals potential corrosion, PG&E states that, as part of this program, it will excavate the affected pipeline segment. PG&E anticipates that it will need to dig at 3 locations in 2019.[587]

PG&E estimates the unit cost to perform surveys using the average cost per mile recorded in 2016. For the excavation work, PG&E estimates the unit

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[583] PG&E Opening Brief at 8-5.

[584] Exh. PG&E-1 at 8-50.

[585] PG&E Opening Brief at 8-53.

[586] PG&E Opening Brief at 8-35.

[587] Exh. PG&E-1 at 8-60.

cost using the historical costs for performing six digs between 2015 and 2017.[588] Accordingly, PG&E's 2019 expense forecast for this program is $5.5 million.[589]

#### 9.7.3. Corrosion Support

This program accounts for the Project Managers, Subject Matter Experts, and Corrosion specialists that support PG&E's Corrosion Control program. These resources perform four main activities: research and testing, data and program management, field support, and investigations. PG&E forecasts the cost to perform testing and research using the historical average costs from 2014 to 2016. PG&E forecasts the cost of data and program management using contracts with third party vendors. For field support, PG&E's forecast is based on the average historical costs for this work from 2015-2016. PG&E forecast the cost of investigation using the hourly rate for its engineers.[590] PG&E's 2019 expense forecast for this program is approximately $2.54 million.[591]

#### 9.7.4. Standard Pacific Gas Line

PG&E allocates a portion of the cost of its Corrosion Control programs to the StanPac line. For this program, PG&E forecasts 2019 expenses of $376,000 and capital expenditures of $74,000 in 2019, $42,000 in 2020, and $43,000 in 2021.[592]

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[588] *Id.* at 8-60.

[589] PG&E Opening Brief at 8-35.

[590] Exh. PG&E-1 at 8-67.

[591] PG&E Opening Brief at 8-7.

[592] *Id.* at 8-7.

### 9.7.5. Test Stations

PG&E uses this program to test the adequacy of CP installed on the underground gas transmission pipeline segments that are at risk of external corrosion.[593] PG&E plans to replace or install 12 coupon test stations in 2019.[594] PG&E's developed its expense forecast using the average historical cost of completed test station installations from 2012-2016.[595] PG&E's 2019 expense forecast for this program is $257,000.[596]

### 9.7.6. Discussion

We find that PG&E's forecasts for the CP, Close Interval Survey, Corrosion Support, StanPac, and Test Station programs are just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. No party opposes these forecasts. Accordingly, we adopt PG&E's capital expenditure and 2019 expense forecasts for the Close Interval Survey, Corrosion Support, and Test Station programs and the capital expenditure and 2019 expense forecasts for the CP and StanPac programs.

## 10. Gas System Operations and Maintenance

PG&E's Gas System Operations programs manage the operation of PG&E's gas transmission and storage system. PG&E's Gas System Planning (GSP) engineers use computerized hydraulic models to determine the gas capacities upon which its GT&S rates and services are designed. PG&E's hydraulic models are based on a standard design day, which represents a set of assumptions regarding the scenario under which gas will be delivered. Each

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[593] *Id.* at 8-4.

[594] *Id.* at 8-5.

[595] Exh. PG&E-1 at 8-54.

[596] PG&E Opening Brief at 8-5.

scenario assumes high demands, plus related contingencies, such as curtailing non-core customer gas flows.

For PG&E's local transmission system, the design day focuses on meeting peak-hour demand, and for its backbone system, peak-day demand. The design day is also differentiated for core and noncore customers and local transmission customers. Because core customers primarily use gas for space heating purposes, core load is temperature dependent. Thus, the design day for core local transmission customers is based on a 1-day-in-90-year APD standard.[597] The design day for non-core customers uses a 1-in-2-year Cold Winter Day (CWD) standard.

Based on the APD and CWD planning standards, personnel at PG&E's Gas Transmission Control Centers (GTCC) monitor and control the physical flow of gas in PG&E's gas transmission system using the Gas Transmission SCADA system and other tools. Approximately 98.5 percent of the gas on PG&E's system originates from outside the State of California and is received at interconnection points along PG&E's backbone transmission system. The remaining gas originates from in-state wells and is received at gas gathering points that connect to PG&E's transmission system.

PG&E delivers gas to retail and wholesale customers. Gas delivered to retail customers flows from PG&E's local transmission system to its distribution system, the point of connection for most retail customers. However, some large retail customers, such as generators, are connected directly to PG&E's backbone transmission system. For wholesale customers, PG&E primarily delivers gas to

[597] Exh. PG&E-1 at 10-11.

Southern California Gas Company through interconnections points located on PG&E's backbone system.[598]

PG&E's underground storage facilities are connected to PG&E's backbone transmission system. Pursuant to the NGSS, PG&E plans to reduce its storage inventory capacity from the 33.4 Bcf to 5 Bcf, which will be maintained at the McDonald Island storage facility.

PG&E uses five programs to manage its Gas System Operations: (1) Capacity Projects, (2) Customer-Connected Equipment, (3) Gill Ranch Storage, (4) Gas Transmission SCADA Visibility, and (5) Operations.

### 10.1. Capacity Projects

PG&E uses hydraulic modeling to identify the extent that increases in customer demand could prevent it from meeting the APD or CWD standards for providing service on its local transmission pipeline.[599] PG&E's Capacity Projects program consists of four sub-programs: (1) Capacity for Load Growth, (2) Capacity Betterment, (3) Capacity to Support Normal Operating Pressure Reductions, and (4) Gas Transmission (GT) Capacity Uprates.

PG&E's Capacity for Load Growth sub-program monitors demand growth on PG&E's pipeline system. PG&E states that demand growth typically occurs when the customer population increases, commercial loads increase, or residential homes expand. An increase in demand growth could cause certain pipeline segments to become constrained, prohibiting PG&E from satisfying customer demands during ADP or CWD conditions. While demand growth occurs on PG&E's distribution pipeline system, such growth also impacts the

[598] Exh. PG&E-1 at 10-9.

[599] *Id.* at 10-22.

transmission capacity on the connected upstream and downstream pipeline systems.[600]

To estimate the capital expenditures for this sub-program, PG&E relies on the following approaches, which PG&E applies based on its familiarity with the project conditions. For projects that are comparable with those that PG&E has recently constructed, PG&E calculates detailed estimates using certain project characteristics, such as pipe diameter and length, or the methodology that PG&E uses for its Pipe Replacement program.[601] For projects with unfamiliar conditions, PG&E uses a high-level estimate of cost per mile of installed pipe. PG&E's capital expenditure forecast for this program is $10 million in 2019, $10.3 million in 2020, and $10.6 million in 2021.[602]

The Capacity Betterment sub-program increases capacity on PG&E's pipeline system by upgrading the diameter or length of existing pipeline segments. PG&E estimates the pace of work for this sub-program using hydraulic modeling. PG&E's capital forecast is based on the escalated average historical sub-program costs from 2014-2016.[603] PG&E's capital expenditure forecast for this program is $1 million in 2019, $2 million in 2020, and $2 million in 2021.

PG&E uses the Capacity to Support Normal Operating Pressure Reductions sub-program to minimize instances of over pressurization on its

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[600] *Id.* at 10-25.

[601] *Id.* at 10-26.

[602] PG&E Opening Brief at 10-2 and 10-10. PG&E reduced the forecast for this program in its testimony by approximately $138.3 million. *Id.* at 10-10.

[603] *Id.* at 10-26.

system by lowering its regulator and overpressure protection set points.[604] PG&E uses hydraulic modeling to determine the scope of work for this sub-program. PG&E estimates capital expenditures for this sub-program using the average cost of comparable projects.[605] PG&E's capital expenditure forecast for this sub-program is $5 million in 2019, $5.2 million in 2020, and $5.3 million in 2021.[606]

The GT Capacity Uprates sub-program manages activities that increase capacity on PG&E's transmission pipeline system by increasing the system pressure rather than installing additional pipeline segments. PG&E plans to perform hydrotests on segments that are uprated as part of this sub-program. In some instances, PG&E must also replace pipeline components so that the pipeline segment can operate at a higher maximum allowable operating pressure.[607] PG&E's 2019 expense forecast for this sub-program is $6 million.

#### 10.1.1. Intervenors

Cal Advocates argues that PG&E's 2019 capital forecast for the Capacity for Load Growth sub-program should be reduced to $17 million over the three-year test period, the average program cost recorded between 2015-2017.[608]

TURN asserts that during its cross examination of PG&E's witness for this sub-program, PG&E admitted that it had cancelled most of the projects that it

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[604] *Id.* at 10-25.

[605] *Id.* at 10-26.

[606] PG&E Opening Brief at 10-2 and 10-10. PG&E reduced the forecast in its testimony by approximately $14.5 million. *Id.* at 10-10.

[607] Exh. PG&E-1 at 10-25.

[608] Cal Advocates Opening Brief at 94. We note that PG&E reduced its estimate in its Initial Brief.

planned to implement during 2019-2021. After removing the cancelled projects, TURN asserts that three remained: one in 2019 for $0.25 million, in 2020 for $2 million, and in 2021 for $0.15 million.[609] Subsequently, however, TURN states that during re-cross examination, PG&E asserted that it had identified three additional projects since completing its workpapers and that PG&E expected that the full set of projects would cost $10 million even though some of them had not yet materialized. TURN does not oppose PG&E's revised forecast, except that it asserts that, in PG&E's rebuttal testimony, PG&E states that it has identified lower-cost ways to satisfy its capacity requirements and that the peak day temperatures are warmer than it previously calculated. Thus, TURN argues that PG&E's revised testimony should account for these circumstances and, therefore, recommends that Commission adopt the following forecast for PG&E's Capacity for Load Growth sub-program: $9.7 million in 2019, $10 million in 2020, and $10.3 million in 2021.[610]

With respect to PG&E's Capacity Betterment sub-program, Cal Advocates argues that PG&E's capital forecast should be based on the most recent average of recorded program costs from 2015-2017, rather than 2014-2016. Using this approach, Cal Advocate s argues that PG&E's estimate for 2019 should be reduced by $167,350 to $884,502.[611]

For PG&E's Capacity for Normal Operating Pressure Reductions sub-program, Cal Advocates argues that PG&E should be required to establish a memorandum account that is subject to a reasonableness review. Cal Advocates

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[609] TURN Opening Brief at 142.

[610] TURN Opening Brief at 143.

[611] Cal Advocates Opening Brief at 95.

argues that PG&E's implementation of this sub-program has been historically inconsistent and that PG&E is unlikely to implement some of the projects for which it has forecasted capital expenses.[612] TURN argues that PG&E should be prohibited from recovering any capital expenditures for this sub-program.

Specifically, TURN asserts that, because PG&E did not perform most of the work authorized during the prior rate case period for this program,[613] that work was deferred. TURN argues that PG&E should be prohibited from retaining in rate base the authorized capital allowances for the deferred work from the 2015 rate case because PG&E has not satisfied the six principles established in the Deferred Settlement. Accordingly, because PG&E's deferred work for this program is valued at $42 million and PG&E is requesting $15 million for the instant rate case period, TURN argues that PG&E's shareholders should fund the capital expenditures for this rate case period.

#### 10.1.2. PG&E Response

Regarding the Capacity Betterment sub-program, PG&E argues that Cal Advocates' recommendation to use the historical recorded three-year average from 2015-2017 is unsupported and, therefore, should be rejected.[614]

PG&E disagrees with TURN's contention concerning cost recovery for the deferred work for the Capacity for Normal Operating Pressure Reductions sub-program. Instead, PG&E argues that it was not required to spend the total expenditures authorized for the 2015 rate case period because it implemented lower cost methods to perform the work necessary while maintaining the safety

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[612] *Id.* at 97.

[613] However, PG&E forecasts that it will perform $700,000 of work during 2018. TURN Opening Brief at 145.

[614] PG&E Opening Brief at 10-12.

and reliability of its system. Further, PG&E argues that, during 2015-2018, it spent $40 million more than its authorized revenue requirement.[615]

#### 10.1.3. Discussion

We find that PG&E's revised capital forecast for its Capacity for Load Growth sub-program is just and reasonable. We disagree with TURN's request to adopt a slightly lower forecast based on PG&E's representation of lower cost methods to satisfy its capacity requirements and that peak day temperatures are warmer than it previously calculated, as PG&E contemplated that information when it proposed a revised forecast during the hearing.

We find that PG&E's capital forecast for the Capacity Betterment program is less credible than Cal Advocates' forecast. Cal Advocates' forecasts use the most recent cost information from 2017, and PG&E has not provided a valid justification for excluding the 2017 recorded amounts. Accordingly, PG&E's capital forecast for the Capacity Betterment programs shall be reduced by $167,350.

With respect to the Capacity for Normal Operating Pressure Reductions sub-program, we agree with TURN's contention that PG&E did not demonstrate that its decision to defer work authorized for the 2015 rate case cycle was in compliance with the Deferred Settlement. PG&E has the burden to prove that its decision is consistent with the six principles set forth in the Deferred Settlement, including that the authorized work was deferred so that PG&E could perform higher priority work. Instead, PG&E asserts that it found lower cost ways to complete the forecasted pace of work that it deemed necessary to meet reliability and safety goals. However, as TURN demonstrated, other than the $700,000 of

[615] *Id.* at 2-36 to 2-38.

work forecasted for 2018, PG&E did not perform any of the projects for which the Commission authorized $42 million in capital expenditures. Accordingly, we find that PG&E's shareholders are required to fund the expenditures for capital projects forecasted over the instant case period for this subprogram in lieu of removing from rate base the majority of the amount authorized during the 2015 rate case period ($42 million less the capital expenditures recorded in 2018).

### 10.2. Customer-Connected Equipment

The Customer-Connected Equipment program consists of activities and equipment necessary for PG&E to connect new customer facilities to PG&E's gas transmission system. This program consists of the two sub-programs: New Business and Meter Sets-Power Plants. The Meter Sets-Power Plants sub-program manages large and complex power plant meters, which are required to connect new customer facilities to PG&E's gas transmission system.[616] The New Business sub-program manages activities necessary to connect large customer load to PG&E's local transmission system.[617]

PG&E forecasts the capital expenditures for this program using the five-year average of historical program costs.[618] PG&E asserts that, because the work for this program is driven by prospective customer-specific demands, it does not have the ability to identify specific projects that it plans to perform during the instant rate case period.[619] PG&E's capital expenditure forecast for

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[616] PG&E Opening Brief at 10-8.

[617] *Id.* at 10-6 to 10-7.

[618] Exh. PG&E-1 at 10-21 and 10-22.

[619] PG&E Opening Brief at 10-22.

this program is $5.8 million for 2019, $5.9 million for 2020, and $5.58 million for 2021.[620]

Cal Advocates argues that PG&E's capital forecast for the New Business sub-program should be based on the five-year historical cost average starting from 2013-2017, rather than 2012-2016. Using this approach, Cal Advocates argues that PG&E's capital forecast should be $2.4 million, rather than an average of approximately $4.5 million. For the Meter Sets-Power Plants sub-program, Cal Advocates argues the Commission should direct PG&E to establish a memorandum account because, in part, PG&E concedes that it is not aware of any new projects that it will be required to implement during the instant rate case period.[621]

PG&E argues that rather than use a forecast approach that excludes 2012 data, it should use a six-year historical cost average from 2012-2017. PG&E states that the program costs from 2017 were unusually low and would be counterbalanced by PG&E's higher spending in 2012. With this revision, PG&E's capital forecast for this sub-program would be $4.4 million per year.[622]

PG&E disagrees with Cal Advocates' contention that PG&E should be required to maintain a memorandum account for the Meter Sets-Power Plants sub-program. PG&E argues that using the five-year average of recorded costs is a reasonable forecasting methodology. Further, PG&E argues that $1.1 million is too small to warrant the time and resources necessary for it to maintain a memorandum account.

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[620] *Id.* at 10-2.

[621] Cal Advocates Opening Brief at 89-93.

[622] PG&E Opening Brief at 10-7.

We agree with PG&E and Cal Advocates' contention that PG&E's capital forecast methodology for its New Business subprogram should incorporate the most recent cost data from 2017. Accordingly, we adopt PG&E's revised forecast of $4.4 million, which is based on a six-year average of historical cost from 2012-2017. We find that PG&E's capital forecast for the Meter Sets-Power Plants sub-program is just and reasonable. We find that using historical recorded cost to estimate future expenditures is a reasonable method to forecast capital expenditures, particularly when specifying predefined projects is not feasible, as is the case here.

### 10.3. Gill Ranch Storage

As part of PG&E's NGSS proposal, it seeks to convert its 25 percent ownership share in Gill Ranch Storage into a utility asset. PG&E's 2019 expense forecast for this program is $2.7 million, and its capital expenditure forecast is $2.75 million for 2019, $261,000 for 2020, and $1.58 million for 2021.[623]

Cal Advocates argues that PG&E's capital forecast should be based on the three-year average of recorded costs, which is $0.261 million.[624] According to Cal Advocates, PG&E justifies its forecast by claiming that it must perform work to comply with new DOGGR rules. Specifically, PG&E's work pace includes integrity testing for 22 wells and retrofitting ten wells. Cal Advocates argues that this justification is insufficient because the DOGGR rules were not final at the time that PG&E calculated its forecast.[625]

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[623] *Id.* at 10-2.

[624] Cal Advocates Opening Brief at 87.

[625] *Id.* at 87.

PG&E disputes Cal Advocates' argument and contends that its forecast is based on the implementation timeline set forth in the final DOGGR rule (*i.e.*, seven years). PG&E reiterates that its forecasted work pace is necessary for it to comply with the DOGGR requirements.

We find that PG&E's forecast is just and reasonable as PG&E has demonstrated that the estimated scope work and related expenditures for the Gill Ranch program are credible. We decline to adopt Cal Advocates' recommended forecast adjustment as PG&E has demonstrated that its proposed forecast is based on requirements set forth in the final DOGGR rule.

### 10.4. Gas Transmission SCADA Visibility

The SCADA system consists of sensors, communications equipment, and commuter systems that together continuously relay real-time operational data to system operators. PG&E's SCADA system allows its operators to monitor approximately 18,000 points on its transmission pipelines and to control the system flows and pressures at approximately 1, 940 points, including storage fields, compressor stations, and valves. The SCADA system also provides alarms to notify operators when certain conditions require immediate attention.[626]

PG&E's Gas Transmission SCADA Visibility program manages the installation of SCADA equipment at various points on PG&E's transmission system. Installing more SCADA devices will assist PG&E's operators in detecting potential operational issues before they escalate.[627] PG&E plans to install a SCADA device every 20 miles on long segments of its backbone transmission system and other high priority pipeline segments. To that end,

[626] Exh. PG&E-1 at 10-7.

[627] *Id.* at 10-31.

between 2019-2021, PG&E plans to install nine SCADA devices on its backbone transmission system and 26 SCADA devices at regulation stations on its local transmission system.[628]

PG&E forecasts capital expenditures for adding SCADA devices based on historical project costs for implementing specific projects on its backbone and local transmission systems.[629] PG&E's capital forecast for the Gas Transmission SCADA Visibility Program is approximately $10.2 million over 2019-2021.[630]

Cal Advocates argues that PG&E's forecast should be reduced based on the three-year historical average recorded costs for this program. As such, Cal Advocates argues that PG&E's capital forecast for 2019 should be $0.35 million.[631]

PG&E disagrees with Cal Advocates' recommendation. PG&E explains that the low recorded costs in 2015 and 2016 are primarily because its program was still in the start-up phase and PG&E was trying to standardize the design of SCADA installations. PG&E asserts that it has resolved the standardization issues and expects to install SCADA systems at the pace stated in its testimony. PG&E reiterates that installing more SCADA devices on its system will assist operators with reducing overpressure events, detecting ruptures and large leaks, and taking timely action to prevent these events from escalating. Accordingly, PG&E request that the Commission adopt its original forecast.[632]

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[628] *Id.* at 10-32.

[629] *Id.* at 10-33.

[630] PG&E Opening Brief at 10-16.

[631] Cal Advocates Opening Brief at 97.

[632] PG&E Opening Brie at 10-15.

We find that PG&E's capital forecast for the Gas Transmission SCADA Visibility program is just and reasonable as the estimated scope work and related expenditures for this program are credible. Accordingly, we decline to adopt Cal Advocates' recommended forecast adjustments.

### 10.5. Operations

To operate its gas transmission system, PG&E relies on staff from the following four departments: GTCC, Gas Control Strategy and Support (GCS&S), Gas Scheduling and Accounting, and GSP. PG&E's staff uses SCADA systems and various accounting and scheduling systems to support customers and manage pipeline capacity and operations on a daily and longer-term basis. This program also accounts for the cost for electric power that is used by the SCADA devices, buildings, and other electric equipment on PG&E's transmission system. In addition, PG&E's staff markets various pipeline and storage services to customers.

To forecast personnel expenses, PG&E calculates a unit cost based on the average annual 2016 salary for employees in each of the aforementioned departments, as escalated using standard rates. For staff responsible for managing the GT&S function, PG&E then multiplies the respective unit cost by the number of full-time equivalent positions. For GCS&S and GSP staff, PG&E applies an escalation factor to maintain pay equity between its engineers and distribution personnel. For staff performing marketing functions, PG&E calculates the expense forecast using historical cost, escalated at standard rates.

This program also manages unclaimed meters. PG&E's 2019 expense forecast for unclaimed meters was determined by averaging recorded costs from 2015-2016, as escalated at standard rates.[633]

In addition, this program accounts for the cost of providing electricity for PG&E's gas compressor units. PG&E operates electric-powered gas compressors located at the Mc Donald Island storage facility, on PG&E's local transmission system in Santa Rosa, and at PG&E's Bethany and Delevan compression stations. PG&E maintains a two-way balancing account for this program.[634] PG&E's expense forecasts for this program are based on the escalated 2016 recorded program costs.

PG&E's 2019 expense forecast for unclaimed meters and personnel, including marketing and business development resources, is $22.1 million.[635] PG&E's 2019 expense forecast for providing electricity to its gas compressors is $21.15 million.[636]

We find that PG&E's 2019 expense forecasts for the Operations program is just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. No party opposes these forecasts. Accordingly, we adopt PG&E's 2019 expense forecasts for this program.

### 10.6. Operations and Maintenance Programs

PG&E's Operations and Maintenance (O&M) programs cover all GT&S assets. The programs include: (1) Locate and Mark, (2) Leak Management,

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633 Exh. PG&E-1 at 10-18.

634 *Id.* at 10-19.

635 PG&E Opening Brief at 10-1; Exh. PG&E-1 at 10-20.

636 *Id.*

(3) Pipeline Patrol, (4) Pipeline Maintenance, (5) Station Maintenance, and (6) Right-of-Way Maintenance – Vegetation Management.

### 10.6.1. Locate and Mark

Pursuant to 49 CFR Part 192.614, PG&E is required to monitor excavation activities to prevent damage to its facilities. Pursuant to California Government Code, Section 4216, Article 2, PG&E is required to join a regional notification system.[637] PG&E uses two subprograms to comply with these regulations: Locate and Mark and Standby.

The Locate and Mark subprogram manages programs that physically locate and mark transmission lines that are near to proposed excavation sites. Contractors notify PG&E of new excavation projects through a regional notification system, the Underground Service Alert. PG&E responds to the notification by using maps to identify underground transmission lines and then marks them with painted paths on the ground. For 2019, PG&E's estimates that it will receive 13,242 locate and market notification tickets.[638] PG&E forecast is based 2016 recorded costs for this subprogram, as escalated through 2019.

PG&E uses the Standby subprogram to monitor an excavation activity (*e.g.,* contractor's digging process) to prevent damage to a pipeline segment. A standby assignment could require field personnel to remain on site for multiple hours, days, or weeks.[639] For 2019, PG&E estimates that it will receive

[637] PG&E is also required to share the cost of operating the regional notification system. PG&E Opening Brief at 9-12.

[638] Exh. PG&E-1 at 9-14 to 9-15.

[639] Exh. PG&E-1 at 9-12.

11,131 standby requests.[640] PG&E's forecast is based 2016 recorded costs for this subprogram, as escalated through 2019.

Cal Advocates agrees with PG&E's forecast methodology but argues that unit costs should be based on 2017 recorded costs, rather than 2016 costs. Cal Advocates asserts that PG&E's 2019 expense forecasts use 2016 recorded costs escalated through 2019; however, the escalated 2017 amount is greater than the 2017 recorded costs. Accordingly, Cal Advocates argues that PG&E's 2019 expense forecast for this program should be adjusted downward by $2.651 million.[641]

PG&E disagrees with Cal Advocates and argues that using the 2016 recorded costs is reasonable because that was the most recent information that it had at the time that it prepared the forecast.[642]

We find that the PG&E's scope of work for this program is just and reasonable. We agree with Cal Advocates' contention that PG&E's forecast should be based on the 2017 recorded costs for this program. Generally, using recent costs to calculate a forecast is more credible that older cost data, and PG&E does not argue that the 2016 recorded cost data is more accurate than the 2017 data. However, to ensure that PG&E is able to seek cost recovery for work performed for the Locate and Mark program in the event the PG&E exceeds its authorized budget, we also direct PG&E to establish a memorandum account for this program. Accordingly, we adopt the adjusted 2019 expense forecasts for this program, as discussed above.

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[640] *Id.* at 9-14 to 9-15.

[641] Cal Advocates Opening Brief at 80-82.

[642] PG&E Opening Brief at 9-6.

### 10.6.2. Station Maintenance

Pursuant to 49 CFR Part 192.605, PG&E is required to perform preventative and corrective maintenance on station facilities. PG&E uses seven subprograms to maintain its stations: one is for station operations and six concern preventative and corrective maintenance for station piping, gas processing equipment, compressor buildings, compressor station support, power units, and storage wells.[643] PG&E's station operations include answering calls from its Gas Control Group, performing emergency shut-down testing, inspecting fire extinguishers and first aid equipment.[644] PG&E's uses recorded information from 2016 to calculate the scope of work and costs for this program. PG&E's 2019 expense forecast for this program is $19.1 million.[645]

TURN disagrees with PG&E's forecast methodology. TURN argues that PG&E's forecast for this program should be based on a five-year average of program costs from 2013-2017, rather than 2016 recorded costs. TURN argues that the five-year average is more credible than PG&E's methodology because the 2016 recorded costs are $3 million higher than the prior two years. Also, because costs have fluctuated between 2012-2017, PG&E cannot assume that future costs will be higher. Accordingly, TURN argues that PG&E's proposed 2019 expense forecast should be adjusted downward by $2.926 million to $16.180 million. TURN also notes that, the 2017 forecast and recorded costs for this program were $17.4 million and $15.214 million, respectively.[646]

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[643] PG&E Opening Brief at 9-6 to 9-7.

[644] *Id.* at 9-7.

[645] *Id.* at 9-7.

[646] TURN Opening Brief at 135-137.

Cal Advocates also disagrees with PG&E's forecast methodology as applied to some of its storage well subprograms. Cal Advocates argues that, except for two of its storage well subprograms, PG&E's forecast should be the three-year average program costs. Cal Advocates argues that PG&E's methodology should determine the forecast for the two storage well subprograms because the DOGGR rules that became effective in 2016 apply to those wells. Accordingly, Cal Advocates argues that PG&E's 2019 expense forecast should be adjusted downward by $1.086 million to $18 million.[647]

PG&E argues that the GHG rule and DOGGR emergency regulations, 1724.(c) and 1724.9(e), have "affected the Station Maintenance Program."[648] PG&E asserts that it will spend $1.6 million to comply with the GHG rules.[649] PG&E also argues that, while its 2017 recorded program costs were lower than its 2016 recorded costs, the preventative and corrective activities necessary to comply with the DOGGR rules could vary from year to year.[650]

We agree with TURN's contention that PG&E's expense forecast should be based on the five-year average of recorded costs, rather than only 2016 recorded costs. PG&E admits that impact of the DOGGR rule is not predictable. The five-year cost average includes amounts that are lower and higher than the 2017 recorded cost. We also find that expense forecast for this program should account for the amount that PG&E estimates it will spend to comply with GHG requirements. Accordingly, we adopt PG&E adjusted 2019 expense forecasts for this program, as discussed above.

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[647] Cal Advocates Opening Brief at 82.

[648] PG&E Opening Brief at 9-10.

[649] *Id.* at 9-8, 9-10.

[650] PG&E Reply Brief at 9-2.

### 10.6.3. Right-of-Way Maintenance

The Right-of-Way and Vegetation Management (ROW) program is provides safe access to PG&E's pipeline facilities. The objectives of the program include maintaining pipeline markers, reducing the negative impact that vegetation can have on pipelines, and informing the public of pipeline locations. ROW has four subprograms. Pursuant to 49 CFR Part 192.707, PG&E uses the Pipeline Marker Maintenance subprogram to maintain and install various types of pipeline markers (e.g., paddle markers, composite markers, stickers on curbs). Pursuant to 49 CFR Parts 192.613 and 192.705, PG&E established the Routine Weed Abatement and Vegetation Management subprograms. Pursuant to GO 112F, PG&E established the Encroachment Structures and ROW Clean-Up subprogram, which provides safe access to pipelines in an emergency and manages the removal of trash and graffiti, among other activities.[651]

For the Pipeline Marker Maintenance subprogram, PG&E estimates that it will maintain 2,300 markers. PG&E's 2019 expense forecast is based on the total number of pipeline markers in the Geographic Information system as of 2016 and the 2017 contract estimates that it received for pipeline marker installation, permits, and material, as escalated through 2019.[652]

For the Routine Weed Abatement subprogram, PG&E estimates the scope of work and 2019 expense forecast using a three-year average of work performed from 2014-2016, as escalated through 2019.[653]

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[651] Exh. PG&E-1 at 9-28 to 9-31.

[652] *Id.* at 9-31.

[653] Exh. PG&E-1 at 9-31.

For the Vegetation Management subprogram, PG&E's estimated scope of work is based on the mileage of pipe that requires weed abatement, the number of trees that require monitoring and removal. PG&E's 2019 expense forecast for this subprogram considers the cost of herbicide application, support costs for land and environmental technical experts, among others.[654]

The costs and scope of work for the Encroachment Structures and ROW Clean-Up subprogram are primarily related to clean-up activities. PG&E manages encroachments primarily through outreach activities.

PG&E's 2019 expense forecast for these subprograms are in Table 32 below. PG&E's 2019 expense forecast for this program is $11.2 million.[655]

**Table 32—Row Maintenance[656]**
**($ Thousands of Nominal Dollars)**

| Line No. | Description | MAT | 2019 Forecast |
|---|---|---|---|
| 1 | Pipeline Maker Maintenance | JOS | $946 |
| 2 | Routine Weed Abatement | JOT | 282 |
| 3 | VM | JTK | 9,093 |
| 4 | Encroachment Structures and ROW Clean Up | JTO | 926 |
| 5 | Total | | $11,246 |

TURN argues that PG&E's 2019 expense forecast for the Vegetation Management subprogram should adjusted downward to exclude $1.2 million that is for contingency purposes. TURN argues that ratepayers should not be required to fund expenses which PG&E has not supported. TURN notes that, if PG&E does not incur costs that are expenses, those funds will flow through to shareholders.[657]

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[654] *Id.* at 9-31.

[655] PG&E Opening Brief at 1-10; *see also* Exh. PG&E-1 at 9-32.

[656] Exh. PG&E-1 at 9-32, Table 9-12.

[657] TURN Opening Brief at 138-139.

PG&E argues that it does not know the precise amount for the $1.2 million because unforeseen events, such as changes in a community's policy for tree removals, could occur. PG&E also argues that the population living near pipelines has grown and that this growth contributes to the increased frequency of encroachment and monitoring costs. PG&E notes that, in the past when PG&E "was reclaiming" ROW, shareholders paid the cost of vegetation management.

We find that PG&E's 2019 expense forecast for this program is just and reasonable, with the exception for the $1.2 million that it has designated for contingency purposes. While PG&E could be required to incur additional costs to respond to changing environmental policies concerning vegetation management and the population growth near pipelines could increase vegetation, requiring PG&E to perform more work to eliminate the risks posed by trees and weeds, we find that the memorandum account that this decision directs PG&E to established to seek recovery of costs incurred to comply with any new federal or state regulations or rule will is more appropriate to address this issue.[658] Accordingly, we adopt the adjusted 2019 expense forecast for this program.

### 10.6.4. Remaining Programs

#### 10.6.4.1. Leak Management

Pursuant to GO 112F and 49 CFR, Parts 192.703, 192.706, and 192.717, PG&E's Leak Management program includes activities for conducting leak

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[658] The memorandum account would allow PG&E to seek cost recover for cost incurred to comply with any new federal or state regulation or rule that is issued between GT&S funding cycles for which PG&E has not been able to incorporate a forecast of costs into a rate case and which are not already addressed and recorded in another account. *See* Section 14.5 of the instant decision.

surveys and grading, repairing leaks, and rechecking leaks.[659] PG&E's Leak Management Program has three subprograms: Leak Survey, Leak Repair, and Leak Re-Checks.

With the Leak Survey subprogram, PG&E performs biannual surveys of its pipelines using either equipment on the ground or helicopters equipped with infrared technology. PG&E estimates that it will perform 12,500 miles of surveys during the rate case period.[660]

PG&E's Leak Repair subprogram is used to manage pipeline repair activities for leaks that are not related to third-party digs. The method PG&E uses to repair leaks depends on the location of the leak and the degree of the risk associated with the damage (*e.g.*, hazardous leaks). The cost of repairing the leak directly correlates with the complexity of the repair. For example, a repair that requires excavation is considered a major repair, while a repair that requires tightening or the application of a lubricant is a minor repair. For 2019, PG&E estimates that it will repair the number of units that it repaired in 2016.[661]

PG&E's Leak Re-Checks subprogram is used to periodically review the status of lower priority leaks identified on its pipeline system. The lower priority leaks could be scheduled for repair more than 6 months after the leak is discovered. PG&E forecasts the number of rechecks using the information from 2016. It reduced the number of rechecks because GO 112F requires PG&E to fix the lowest priority leak, rather than continuing to monitor wither the status of the leak has escalated.

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[659] PG&E Opening Brief at 9-2.

[660] Exh. PG&E-1 at 9-16.

[661] *Id.* at 9-18.

PG&E's 2019 expense forecast for the Leak Management program is $6.1 million,[662] which is based on 2016 unit cost data for each respective subprogram.[663]

#### 10.6.4.2. Pipeline Patrol

Pursuant to 49 CFR Part 192.702, PG&E is required to monitor the surface conditions on and adjacent to pipelines to detect leaks, construction activity, and other factors affecting the safety and operation of the pipeline. Using ground equipment and aerial resources, PG&E's Pipeline Patrol program monitors vegetation growth, gas leaks, class location changes, damage to facilities. PG&E's scope of work is based on the patrol frequency required by 49 CFR Part 192.702, as modified to include more patrols based on PG&E's assessment of the prevention benefits. PG&E estimates that it will perform aerial patrols of its entire system at least 12 times per year, and that the number of ground patrols will be exceed the hours recorded in 2016 because PG&E added another full-time position.[664]

PG&E's 2019 expense forecast of $6.5 million is based on the 2016 recorded program costs, escalated through 2019.[665]

#### 10.6.4.3. Pipeline Maintenance

Pursuant to 49 CFR Parts 192.605, 192.701, 192.703, 192.739, 192.745, and 195.406, PG&E is required to maintain its pipeline system, from California's northern border with Oregon to its southern border with Arizona.[666] This

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[662] PG&E Opening Brief at 9-2.

[663] Exh. PG&E-1 at 9-16 to 9-19.

[664] *Id.* at 9-22.

[665] PG&E Opening Brief at 9-3.

[666] *Id.* at 9-3.

program uses eight subprograms: six concern preventative and corrective maintenance for various equipment, such as manual valves and meters, and two concern the operation of transmission pipelines and regulator stations. Because this program requires manual work, PG&E's employees are required to travel to the equipment and facility locations. PG&E's 2019 forecast for this program is $9.7 million,[667] which is based on the 2016 recorded costs for this program, as escalated through 2019.[668]

#### 10.6.4.4. Discussion

We find that PG&E's forecast for the Leak Management, Pipeline Patrol, and Pipeline Maintenance are just and reasonable as PG&E provided enough evidence to demonstrate that the forecasts are credible. No party opposes these forecasts. Accordingly, we adopt PG&E's 2019 expense forecast for the Leak Management, Pipeline Patrol, and Pipeline Maintenance programs.

### 10.7. Technology and Security

The Technology and Security program to manages research and development, innovation, technology and security activities for PG&G's gas operations. In addition, this program is designed to assist PG&E in identifying abnormal system conditions, reducing response time for addressing planned and unplanned planned events, integrating data, and delivering efficient solutions that allow employees to access relevant information. PG&E forecast capital expenditures of $30 million for 2019, $31 million for 2020, and $22 million for 2021.[669]

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[667] PG&E Opening Brief at 9-3.

[668] Exh. PG&E-1 at 9-23 to 9-24.

[669] *Id.* at 12-3.

PG&E's 2019 expense forecast is based on a stipulation between it and Cal Advocates. PG&E initially requested $23.3 million, but Cal Advocates proposed a reduction to PG&E's forecast to reflect the three-year average of recorded costs between 2016-2018. In the stipulation, the stipulating parties agree that $21.1 million is a reasonable forecast and that they will meet before the next rate case to discuss the presentation and reporting of PG&E's Gas Operations Technology and Security projects.[670] No party protests the stipulation.

We find that the stipulation is reasonable in light of the record. Accordingly, the joint stipulation in Exhibit JS-02 is adopted.

### 10.8. Other Issues

#### 10.8.1. Limited Trading Authority

PG&E estimates that there will be under-pressure issues on the Baja path and thus recommends implementing process changes that will provide for Baja minimum flows for system reliability. Customers prefer to ship gas to PG&E Citygate from the north using the Redwood path, rather than from the southwest using the Baja path, because gas supply from the north is generally less expensive. This preference could cause reliability issues on PG&E's system because – low flow on the Baja path will reduce pressures, making it difficult for PG&E to deliver gas to customers located between Topock and the California-Arizona border. Also, two firm transportation contracts remain on the Baja path, one belongs to CGS and will be phased out as part of the NGSS.

PG&E states that it would identify the impending Baja supply shortfall and notify Wholesale Marketing and Business Development department

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[670] Exh. JS-02 at 1-2.

(WM&BD) on the same or next day.[671] To resolve the low flow issue, PG&E requests that the Commission authorize it to purchase gas supplies upstream of the Hinkley compressor station and sell the gas at Citygate so that PG&E can recover as much of the purchase price as possible. If PG&E is unable to procure the requested gas, it proposes to rely on CGS or its Electric Gas Supply group to procure from gas at Topock and WM&BD would later sell at Citygate on the same day.

PG&E proposes to track the spot market transactions in its Balancing Charge Account. PG&E proposes to allocate to all customers the difference between the spot market purchase cost and the sales revenues using PG&E's AGT filing. In addition, PG&E states that is open to reporting the date, price, and value of the transactions on a quarterly basis on its Pipe Ranger website. If PG&E's Gas Control group determines that spot gas purchases are not sufficient to maintain reliability, PG&E proposes to use a Request for Offer program to solicit proposals that will "create gas supply structures designed to support Baja minimum flow requirements with minimal cost to customers."[672]

We find that PG&E's proposed minimum requirements process is just and reasonable, subject to conditions. PG&E's proposal is necessary to maintain minimum flow requirements, which is necessary to ensure that its gas transmission system is reliable. However, we find that additional reporting requirements are necessary to understand the volume of transactions and promote transparency. PG&E must file an annual report that notes the date of each purchase of gas by PG&E to support Baja path reliability (through any of its

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671 Exh. PG&E-1 at 10-41.

672 PG&E Reply Brief at 10-4.

departments, including WM&BD or Electric Gas Supply) from suppliers, the amount of gas purchased, the purchase price, and the sales price. The report should also include the total net cost of the program. With respect to the RFO process, we find that PG&E must submit a Tier 2 Advice Letter before it selects an offer through that process.

#### 10.8.2. Quarterly OFO

Pursuant to a settlement approved in D.00-02-050, PG&E is required to issue quarterly reports on the number and character of OFOs it enforced in the prior quarter. PG&E issues an OFO when its backbone pipeline inventory could be unable to support imbalances between the volumes of gas that customers are consuming with the amount that they are delivering on the system. These imbalances can cause unsafe pressure fluctuations in t the backbone pipeline system and downstream supply issues.

PG&E states that this requirement was implemented to satisfy customers' complaints when the OFO process was relatively new. However, customers have accessed to the quarterly report only 15 times over the last 12 months, which is insignificant given that PG&E has 330 shippers. Thus, PG&E proposes to discontinue generating the report.

We find that the OFO Quarterly Report continues to be useful. The Commission's Energy Division uses this report to monitor PG&E's OFO process, and the interest in the report may increase after PG&E implements the NGSS because PG&E may be required to issue more OFOs.

### 10.8.3. Line 407 Reasonableness

Line 407 extends 26 miles from Yolo to Placer County, expanding PG&E's local transmission system in the Sacramento Valley.[673] During the 2015 GT&S rate case, PG&E proposed a forecast of $175 million to construct Line 407.[674]

In D.16-06-056, the Commission authorized cost recovery for the construction of Line 407 for up to $157 million beginning after the in-service date, and it authorized a memorandum account to track costs that exceed that amount. The Commission also required a reasonableness review for all project costs for Line 407.[675]

On April 30, 2018, PG&E filed a report to demonstrate the reasonableness of the cost that it incurred for Line 407. In the report, PG&E states that Line 407 became operational on October 21, 2017, and that as of December 31, 2017, PG&E incurred $180.8 million to construct the line. PG&E states that the project will incur costs in 2018 and beyond to implement initial in-line inspections, resolve land acquisition issues, and complete various project close-out tasks. PG&E forecasts that remaining tasks will cost $11.0 million, bring the total project costs to $191.8 million.

PG&E also argues that the actual and forecasted costs for the Line 407 project are reasonable based on the justified need for the project,[676] summary of project costs,[677] and cost comparisons. Accordingly, PG&E requests that the

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[673] Exh. PG&E-28 at 1-3.

[674] D.16-05-056.

[675] Exh. PG&E-28 (citing D.16-06-056, Ordering Paragraphs 57 and 58).

[676] *Id.* at 8-9. Line 407 was implemented to meet its Abnormal Peak Design standard and resolve over-pressurization issues on its system. *Id.*

[677] Exh. PG&E-28 at 9-13.

Commission find that all of the recorded and forecasts costs, $191.8 million ($180.8 million of recorded costs and $11.1 million of forecasted costs), are reasonable and should be incorporated into PG&E's 2019 revenue requirement. If PG&E spends less than $191.8 million, it proposes to file an advice letter to return any over-collections to ratepayers though the AGT. If, however, PG&E spends more that $191.8 million, it proposes to file a Tier 2 advice letter for a reasonableness review of any additional costs.[678] PG&E request approval to discontinue the Line 407 memorandum account because the reasonableness review of the line will be complete when the instant rate case concludes.[679]

Cal Advocates states that the report supports a finding of reasonableness for PG&E's spending up to the authorized cap of $157 million and the "capital expenditures above the authorized cap."[680]

We find that PG&E's report demonstrates that the recorded capital expenditures of $180.8 million has been reasonably incurred and that the line is in-service. No party disputes the assertions in PG&E's report. However, we find because the Commission ordered a reasonableness review of all project costs, PG&E must track the remaining forecasted expenses of $11 million in the existing memorandum account for this program. Accordingly, we decline PG&E's request to file a Tier 2 Advice Letter to manage over-collections or additional costs. The reasonableness review of PG&E's memorandum account will be conducted as part of the next rate case.

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[678] *Id.* at 34.

[679] PG&E Opening Brief at 16-24.

[680] Cal Advocates Opening Brief at 85.

## 11. Results of Operations

PG&E's revenue requirement is based on its forecasted expenses and capital expenditures as modified by the adjustments adopted in this decision. A summary of the components of PG&E's revenue requirement is below.

### 11.1. Operating and Maintenance Expenses

PG&E's O&M expense includes labor, materials, supplies, contracts and other expenses related to operating and maintaining its GT&S facilities and providing customer service. PG&E provides the estimated O&M expenses for the rate case period in Exh. PG&E-1, Chapter 3, with supporting detail in Chapters 5-13 of Exh. PG&E-1 and PG&E-2.[681]

Since the 2015 GT&S rate case, PG&E has made two changes to its forecasting methodology. First, PG&E revised the cost accounting methodology that it uses to gather and allocate costs to its programs and services. The new methodology applies employee labor costs to workorders,[682] but excludes the related-overhead costs, as those costs are now tracked separately.[683] As a result of this change, some of the costs that were recorded in PG&E's program areas are now recorded as Administrative and General (A&G) expenses.[684] Second, PG&E reorganized its major work categories and major activity types.[685]

### 11.2. Administrative and General

PG&E's A&G expenses include the salaries and expenses of personnel not engaged in directly supporting specific utility functions, such as insurance,

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[681] PG&E Opening Brief at 14-1.

[682] Exh. PG&E-1 at 20-7.

[683] *Id.* at 3-6.

[684] *Id.* at 14-2.

[685] *Id.* at 3-8.

workers compensation payments, consultant fees, and employee benefits. These expenses provide general benefits; therefore, PG&E allocates the total A&G expense among its unbundled cost categories (UCCs) using the O&M expense labor ratios.

For the 2019 GT&S UCCs, PG&E proposes to allocate the A&G expenses adopted in the 2017 GRC D.17-05-013, as adjusted to account for the revisions to PG&E's new cost accounting methodology.[686] PG&E proposes to update the GT&S A&G expenses with the amount that the Commission adopts in PG&E's 2020 GRC proceeding.

PG&E proposes to remove from its 2019 GT&S revenue requirement officer compensation that is prohibited pursuant to SB 901.[687] PG&E, Cal Advocates, and TURN agree to a joint stipulation providing that (1) PG&E will record in a memorandum account officer compensation, consistent with the definition of "officer" provided in Resolution E-4964, (2) PG&E will reduce its GT&S operating expense by $1.4 million and capital expenditure by $455,000, and (3) the revenue reduction will be effectuated in Results of Operation model used to support the instant decision (3).[688]

PG&E will record the pension forecast as a separate line item in the Gas Preliminary Statement Part C and address that forecast in its AGT filing and, if necessary, by filing Advice Letter.[689]

We find that PG&E's methodology for computing A&G expenses is reasonable. We also find that the joint stipulation concerning officer

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[686] PG&E Opening Brief at 14-2.

[687] Exh. PG&E-33 at 1-2.

[688] Exh. JS-08 at 3-4.

[689] PG&E Opening Brief at 14-2.

compensation is reasonable in light of the record. Accordingly, the joint stipulation in Exhibit JS-08 is adopted.

### 11.3. Plant and Rate Base

Plant includes the costs of PG&E's common plant assets, such as its headquarters building, and its GT&S utility assets that are used and useful in providing public utility service to PG&E's customers. PG&E's GT&S assets include transmission pipes, compressor stations and storage wells. PG&E's GT&S assets represent 92 percent of the plant assigned to the GT&S rate base. PG&E forecasts plant additions, plant retirements, and allocation of common, general and intangible plant.[690] To estimate utility plant for the rate case period, PG&E proposes to use the recorded plant as of December 31, 2016, and the forecasted net plant additions for 2017, 2018, and 2019.[691] PG&E asserts that it appropriately allocated common plant and converted its 2017-2021 forecasted capital expenditures into gross plant additions. PG&E's request that the Commission adopt its 2017, 2018, and 2019 weighted average plant of $6,273 million, $7,445 million, and $8,398 million, respectively.[692]

PG&E's rate base represents the unrecovered investment that PG&E has made in utility plant. The rate base amount is used to determine the return component in the revenue requirement calculation. PG&E estimates rate base by combining (1) the plant estimate described above, 2) its forecast of accumulated

[690] PG&E Opening Brief at 14-3.

[691] The estimates for the forecasted net plant additions are described in the following sections: Transmission Pipeline, Storage, Facilities, Corrosion Control, Operations and Maintenance, Gas System Operations, Natural Gas Storage Strategy, Gas Operations Technology and Security, Other Gas Transmission and Storage Support. (Exh. PG&E-2 at 14A-2. )

[692] PG&E's weighted average forecasts for 2017 and 2018 are $6,473 million and $7,445 million, respectively. Exh. PG&E-2 at 14A-3.

depreciation,[693] and (3) its forecast of certain rate base components.[694] PG&E's request that the Commission adopt its recorded 2016 weighted average rate base of $3,140 million, and its forecasted 2017, 2018, and 2019 weighted average rate base of $3,767 million, $4,583 million, and $5,306 million, respectively.[695]

TURN argues that PG&E's proposed plant additions for 2017 and 2018 should be reduced. TURN assert that, from 2015-2017, PG&E's actual capital expenditures have been consistently below the amounts authorized in D.16-06-056. For example, PG&E was authorized to spend $838 for 2017 but only recorded $745 million.[696] Accordingly, TURN asserts that, for PG&E's 2017 capital expenditures, the Commission should adopt PG&E's actual recorded capital expenditures, instead of its forecast.

With respect to PG&E's 2018 capital expenditures, TURN argues that PG&E's forecast of $1.099 billion dollars should not be included in the test-year rate base because, based in part on the evidence in this proceeding, PG&E will not spend $1 billion and, therefore, it should not be permitted to recover that amount from ratepayers. TURN asserts that in PG&E's data response, submitted September 11, 2018, PG&E admits that its current estimate for 2018 is $965 million.[697] However, during the hearing, PG&E stated that it still may include the $1.099 billion estimate in rates.

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693 PG&E's forecast of accumulated depreciation is presented in Exh. PG&E-1, Chapter 14B. Exh. PG&E-2 at 14A-7.

694 Exh. PG&E-2 at 14A-7.

695 PG&E's weighted average forecasts for 2017 and 2018 are $6,473 million and $7,445 million, respectively. Exh. PG&E-2 at 14A-3.

696 TURN Opening Brief at 157.

697 TURN Opening Brief at 157 (citing Exh. TURN-11 at 2-3).

TURN argues that PG&E's revised estimate is also excessive. TURN contends that as of August 2018, PG&E had only spent $580 million. According to TURN, at the hearing, PG&E explained that it expects "an uptick in spending toward the end of the calendar year."[698]

Accordingly, TURN argues that, for PG&E's 2018 capital expenditures, the Commission should adopt one of the following options: the amount authorized in D.16-06-056 for 2018 ($771 million); (2) PG&E's recorded costs for 2017 ($745 million) plus escalation; or (3) the amount of PG&E's recorded 2018 capital expenditures and beginning test-year rate base.

TURN recommends the third option and notes that, to implement that option, the Commission would need to direct PG&E to submit recorded 2018 capital expenditures in late-filed exhibit, which would be subject to review and comments by the parties.[699]

For its 2017 capital expenditures, PG&E does not object to using 2017 recorded capital costs to compute rate base. For its 2018 capital expenditures, however, PG&E argues that the Commission should reject TURN's recommendations. PG&E argues that it should not be required to use its 2017 recorded costs or forecast as a basis for determining its 2018 capital expenditures.[700] PG&E contends that using its 2017 recorded costs or forecast to determine its 2018 forecasted expenditures would require PG&E to replace its thoughtful forecast with "an arbitrary number hundreds of millions lower than

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[698] *Id.* at 159.

[699] TURN Opening Brief at 158-159.

[700] PG&E Opening Brief at 14-5.

what PG&E is likely to actually invest."[701] Moreover, PG&E argues the 2017 forecast is approximately $200 million lower than PG&E's capital budget as of the mid-2018 ($965 million).[702]

With respect to using 2018 recorded costs, PG&E argues that "[t]he Commission can and should adopt a reasonable forecast based on the evidentiary record and, as is always the case in forecast ratemaking, a true-up will occur in the next rate case."[703]

We find that PG&E's proposed plant and rate base should be revised, as discussed below. First, we agree utilities are generally required to true-up rate base in the next rate case. The prior rate case period included 2017 and 2018; thus, it is appropriate for the instant decision to direct PG&E to use recorded costs to reflect the recorded rate base for those years. Thus, for its 2017 capital expenditures, we direct PG&E to use its recorded costs of $745 million.

The estimate that PG&E provided for 2018, $965 million, is $121 million less than the $1 billion dollar estimate and is more credible, because it was calculated more recently. To reflect the recorded capital expenditures for 2018 in its 2019 revenue requirements, PG&E must refund ratepayers any overcollections during the 2019 gas true-up. Thus, we require PG&E to reflect the 2018 recorded rate base for developing the beginning balance for the 2019 test-year rate base. PG&E shall update its AGT for each year of the rate case period to reflect that rate base adjustment. We also direct PG&E to a file Tier 1 Advice letter, on

[701] PG&E Opening Brief at 14-5.

[702] *Id.* at 14-6.

[703] *Id.* at 14-6.

October 1, 2019, stating the amount of its recorded 2018 capital expenditures that it intends to add to rate base.

### 11.4. Decommissioning and Depreciation Expense

This section discusses PG&E's proposal for estimating deprecation expenses for assets other than the Los Medanos and Pleasant Creek storage fields, and its proposal for recovering decommissioning and depreciation expense for the Los Medanos and Pleasant Creek storage fields. In addition, this section discusses PG&E's estimates for calculating depreciation reserve for all of its GT&S assets.

Depreciation expense recovers the original cost of fixed capital less estimated net salvage value over the useful life of the property. Pursuant to CPUC SP U-4, PG&E's depreciation expense is determined using a straight-line, remaining-life method. The remaining-life method allocates the net plant balance, adjusted for net salvage, over the estimated remaining life of the asset. PG&E periodically adjusts the estimates of the remaining life and salvage value (depreciation parameters) so that it can recover the remaining service value by the time the asset is retired from service. For the instant rate case, PG&E uses the depreciation parameters based on a study performed by Gannett Fleming.[704]

Specifically, for each depreciable group of GT&S plant in service, the depreciation study determined the average service life, using survivor curves, and the net salvage percentage. Within a group of similar assets, some of the individual assets could retire at different times, and each group could have a different retirement pattern. PG&E gathered retirement data from 1980 to 2016

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[704] Exh. PG&E-2 at 14B-2. PG&E states that the depreciation parameters presented in the study were adopted in its 2017 GRC for common, general, and intangible plant allocations. (*Id.* at 14B-2 (citing D.17-05-013).)

using the retirement rate method, which relies on actual retirement data and installation dates. Using this retirement data, PG&E's survivor curve graphically depicts the amount of property that survives each year of the life expectancy for the group. PG&E estimates the average service life for each asset group "by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero."[705] To estimate the net salvage value of its GT&S plant in service asset groups, PG&E evaluated inflation, age, and historical and forecasted cost of removal and gross salvage figures.[706] [707]

PG&E states that, during the proceeding, it entered into a stipulation with Cal Advocates, to resolve the disputes concerning the average useful life for assets other than the Los Medanos and Pleasant Creek storage fields (Exh. JS-03). PG&E states that the disputes generally concerned instances where the results of its study and Cal Advocates' study differed on the length of a survivor curve or a net salvage estimate. The stipulation provides an overall depreciation rate of 2.28 percent, which is approximately midway between the rates that each party proposes. PG&E requests that that the Commission adopt the account-specific parameters in the stipulation.[708] Accordingly, PG&E's 2019 forecast for depreciation expense is $274.5 million.[709]

Second, as discussed earlier, PG&E proposes to decommission Los Medanos and Pleasant Creek from January 1, 2022 through the end of 2023. As

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[705] Exh. PG&E-2 at 14C-10.

[706] *Id.* at 14C-31.

[707] *Id.* at 14C-37.

[708] PG&E Opening Brief at 14-12.

[709] *Id.* at 14.8.

with the net book value (NBV) for these assets, PG&E proposes to recover the decommissioning costs over the remaining useful life for the storage fields, which is 2019-2021, as discussed below. PG&E argues that including these costs in current rates will reflect the cost of providing gas service.

PG&E's forecast for decommissioning expense is $88.8 million,[710] of that amount $29.6 million will be amortized for each year over 2019-2021. However, consistent with D.92-12-057, which approved a method for periodically updating forecasted decommissioning to reflect changes in regulatory requirements and technology conditions, among others, PG&E proposes to reflect any changes to its decommissioning cost estimate in its next GT&S rate case.[711]

PG&E excluded the Los Medanos and Pleasant Creek storage fields from the depreciation study. PG&E proposes to shorten the useful life of these storage fields to coincide with the date that it proposes to begin decommissioning them: January 1, 2022. To calculate depreciation expense for the storage fields, PG&E proposes use the NBV as of 2016, which is $80 million, and all post-2016 capital additions, which total $23.6 million for 2017-2021.[712] Thus, over a period of three years (2019-2021), PG&E proposes to recover the storage fields' 2016 NBV and forecasted capital additions from 2017-2021. PG&E's expense forecast for the Los Medanos and Pleasant Creek storage fields is $96.9 million over 2019-2021.[713]

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[710] Exh. PG&E-2 at 14B-16; *see also* Exh. PG&E-1 at 14B-15 (citing Workpaper Table 14B-DG-1 and Table 14B-GD-2). The estimate includes the costs to plug and abandon wells, restore and remediate plant site, and to remove above ground facilities. These estimates are discussed in the following sections of the instant decision: Section 5, NGSS; Section 6, Storage; Section 7, Facilities; Section 13, Other Gas Transmission and Storage Support.

[711] Exh. PG&E 2 at 14B-15.

[712] *Id.* at 14B-12.

[713] Exh. PG&E-1 at 14B-12.

Third, to calculate the depreciation reserve balances for the 2019-year end, PG&E adds forecasted depreciation expense and gross salvage receipts for 2019 to the forecasted 2018 reserve balance and then subtracts the forecasted retirements and cost of removal spending during 2019.[714]

### 11.4.1. Intervenors

Cal Advocates asserts that the Stipulation set forth in Exhibit JS-03 resolves its dispute with PG&E concerning the average service lives, survivor curve types, net average rate, and depreciate accrual rates for assets unrelated to ceasing operations at Los Medanos and Pleasant Creek.

With respect to decommissioning the storage fields, Calpine argues that PG&E should be required to test the market for interested purchasers of the storage fields before seeking retirement option.[715] Calpine argues that selling the storage fields would avoid expensive decommissioning costs.[716] Similarly, Commercial Energy asserts that, if PG&E sells Los Medanos and Pleasant Creek, the decommissioning costs for PG&E's ratepayers will be zero, rather than $88 million.[717] Cal Advocates argues that, if the Commission authorizes PG&E to decommission the storage fields, the amortization period for decommissioning the storage assets should span eight years, rather than three years, to reduce the impact the rate increase will have on ratepayers.

Similarly, Cal Advocates argues that the depreciation useful life of the assets should be extended to eight years. Cal Advocates argues that PG&E's

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[714] *Id.* at 14B-13.

[715] Calpine Opening Brief at 41-43.

[716] *Id.* at 41-43.

[717] Commercial Energy Opening Brief at 5.

proposal violates SP U-4, which provides that the purpose of depreciation expense is to recover original cost of fixed capital (less estimated net salvage value) using "an equitable plan of changes to operating expense or clearing accounts."[718] Cal Advocates asserts that PG&E's proposal for a shorter useful life will increase depreciation expense for those facilities from $3.4 million in 2018 to $32.15 million in 2019, causing a ten-fold increase that is inequitable.

In addition, Cal Advocates states that, while SP U-4 provides that recovering the original cost of fixed capital over (less estimated net salvage value) over the useful life is a basic objective of depreciation, there is an exception for "extraordinary obsolescence," as is the case here because PG&E's NGSS is driving the closure of the storage fields. Cal Advocates argues that requiring PG&E to depreciate the storage fields over a longer useful life is consistent with Commission precedent regarding stranded assets. Cal Advocates argues that it is unreasonable to impose depreciation expense at the magnitude proposed within a short timeframe.

To limit intergenerational inequities, Cal Advocates proposes a schedule that allows PG&E to use the current depreciation rates for the storage fields over the next three years, after which (beginning 2022), PG&E should be required to convert the remaining net book value of Pleasant Creek, and Los Medanos if applicable, to regulatory assets and to amortize them over five more years, with no return on investment as the assets would no longer be in service.[719] This approach would allow PG&E to recover depreciation expense over eight years,

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[718] Cal Advocates Opening Brief at 114-115.

[719] Cal Advocates Opening Brief at 117 (citing D.85-08-046, D.85-12-108, D.11-05-018).

from 2019-2026, and is appropriate because this timeline is still shorter than the original remaining useful life with is of approximately 27 years.

#### 11.4.2. PG&E

PG&E disagrees with Cal Advocates' contention that the time span for depreciating and decommissioning the Los Medanos and Pleasant Creek storage fields should be extended. With respect to depreciation, PG&E argues that Cal Advocates' approach ignores the concept of intergenerational equity, a ratemaking principle that the group of customers that realize the benefit should pay the cost associated with the benefit.[720] PG&E argues that, because the depreciation rate that is charged to customers after the assets has been retired will increase, "[a]dopting Cal Advocates recommendation would make the customers who are not benefiting from the assets pay more than the customers who will benefit from the assets."[721]

However, PG&E states that if the Commission defers consideration of retiring the Los Medanos facility until the next rate case, PG&E argues that rather than allow depreciation rates to use the current useful life (approximately 27 years), PG&E argues that the Commission should direct a 7-year remaining life. PG&E opposes using the existing useful life of the storage fields to determine the depreciation expense that should be recovered over the rate case period. PG&E argues that the Commission should set the depreciation expense based on the most likely outcome, which is the retirement and decommissioning of the assets, rather than a sale.[722]

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[720] PG&E Opening Brief at 14-16.

[721] *Id.* at 14-16.

[722] PG&E Opening Brief at 14-20.

PG&E argues that SP U-4 contemplates a deviation for "extraordinary obsolescence, as Cal Advocates states, but only pursuant to consultation with experienced individuals."[723] PG&E admits that the specialist in the SP U-4 refers to a combination of Energy Division and Cal Advocates' staff, but argues that Cal Advocates' witness has "no formal education, training, or certification related to accounting or depreciation. . . ."[724] If, however, the Commission concludes that production will continue beyond 2021, PG&E argues that it should adjust the depreciation recovery period accordingly.[725]

### 11.4.3. Discussion

We find that the stipulation concerning the depreciation rates for the GT&S assets other than Los Medanos and Pleasant Creek is reasonable in light of the record. Accordingly, the joint stipulation in Exhibit JS-03 is adopted.

With respect to the Los Medanos and Pleasant Creek storage fields, we find that the amortization period to recover decommissioning costs should be five-years from 2019-2023. As discussed earlier, PG&E's authority to decommission Los Medanos is subject to the outcome of a Tier 2 advice letter, which PG&E must file in 2022, and PG&E is required to file a plan to test the market. So, if approved, decommissioning activities could be delayed until 2023 or beyond.

We also find using five years as the useful life for Los Medanos and Pleasant Creek Storages fields is reasonable. If PG&E is authorized to decommission Los Medanos, it is unlikely that most of the storage wells at

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[723] *Id.* at 14-17 (citing CPUC Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals at 42).

[724] *Id.* at 14-18.

[725] *Id.* at 14-21.

Los Medanos will be fully decommissioned before 2023. Thus, prior to that time, between the two storage fields, most of the wells will provide production gas service and, therefore, will be used and useful. Moreover, we agree with intervenors who raise concerns that the magnitude of the depreciation expense increase (ten-fold) for the storage fields over a short timeframe, such as three years, would pose an unreasonable burden for ratepayers, particularly given the significant rate increase that was authorized in the 2015 rate case.[726]

We disagree with PG&E's contention that extending the useful life of the storage assets would cause intergenerational inequities as it asserts that the cost savings from the NGSS will benefit ratepayers for the next 20 years. We agree with intervenors who contend that a sale would be preferable as it would eliminate $88.8 million in forecasted decommissioning expenses and could reduce rates with the sales revenues. Thus, as directed above, PG&E will submit a Tier 1 Advice Letter demonstrating its plan to sell the storage fields.

If the decommissioning of Los Medanos is not approved, PG&E must file a Tier 1 Advice Letter to propose a method for refunding ratepayers for the associated decommissioning expense and depreciation expense beyond the amount the PG&E would have recovered using the useful life authorized in the 2015 GT&S rate case.

### 11.5. Taxes

PG&E's calculations of its expected business taxes, income taxes, deferred tax balances, payroll taxes, property taxes, and other taxes (*e.g.*, hazardous waste) in the case are in Tables 15B-2, 15B-3, and 15B-4 of Exhibit PG&E-2. No party

[726] *See* D.16-06-056 at 31.

disputed PG&E's proposed methodology or rates, and we find that PG&E's proposals are reasonable.

## 12. Post-Test Year Ratemaking Mechanism

PG&E and Cal Advocates jointly propose a mechanism for PG&E's PTYR for 2020-2021 and if adopted, 2022.[727] The stipulation is unopposed and similar to the PTYR that Cal Advocates and PG&E proposed in PG&E's prior GT&S rate case, except for adjustments to various program forecasts. Specifically, PG&E and Cal Advocates disagree as to the revenue requirement that should be adopted and the treatment of the Los Medanos and Pleasant Creek storage fields. Thus, the stipulation proposes different PTYR requirements to reflect the Commission's decision on these issues.[728] No party opposes the stipulation.

We find that the stipulation is reasonable. Accordingly, we adopt the Joint Stipulation in Exhibit JS-05.

## 13. Transmission and Storage Rate Design and Cost Allocation

### 13.1. Backbone Transmission Rate Design and Average Load Factor

PG&E provides backbone transmission service on four paths: Redwood, Baja, Silverado, and Mission. Pursuant to the Gas Accord Settlement V in D.11-04-031 (Gas Accord),[729] PG&E calculates a separate revenue requirement and backbone transmission rate for each path, except the Mission Path because its as-available rate is zero.[730]

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[727] Exh. JS-05.

[728] PG&E Opening Brief at 15-2 (citing JS-05 at 1).

[729] PG&E Opening Brief at 17-9.

[730] Exh. PG&E-2 at 16B-2.

PG&E states that it calculates each backbone transmission rate by dividing the cost allocated to that path by the product of the path capacity multiplied by the system average load factor.[731] PG&E calculates the average load factor by dividing the total backbone demand for the backbone transmission paths by the total backbone capacity on the transmission paths, with some adjustments.[732] PG&E asserts that the Commission adopted this rate design methodology in D.16-06-056.[733] In addition, PG&E proposes to continue the rate differential between the Baja and Redwood paths, as discussed in the next section. The rate differential is a part of PG&E's backbone rate design.

PG&E states that it will calculate the final load factors after the revenue requirement, throughput forecast, and backbone rates are adopted in the instant proceeding. However, based on its current application, PG&E forecasts that the load factor for its backbone transmission rates is 61.98 percent for 2019, 61.86 percent for 2020, 62.22 percent for 2021, and 62.68 percent for 2022.[734]

We find that PG&E's methodology for its backbone rate design and load factor is just and reasonable. We note that no party protested the methodology. Accordingly, we adopt PG&E's backbone rate design and load factor methodology.

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[731] *Id.*

[732] *Id.*

[733] PG&E Opening Brief at 17-8 (citing D.16-06-056 at 464).

[734] *Id.* at 17-8.

### 13.2. Differential Rate Between Baja and Redwood Paths

PG&E initially proposed to retain the fixed Baja-Redwood path rate differential that the Commission adopted when it approved the Gas Accord.[735] To implement the differential, PG&E equalizes the revenue requirements on the Baja and Redwood paths so that the difference between the reservation charge for the two paths is approximately $.04 per decatherm (Dth). In equalizing the revenue requirements, the reservation charge for the Baja line is higher than the charge based solely on the revenue requirement for that line.[736] Subsequently, PG&E agreed to a stipulation with GTN. In the stipulation, the stipulating parties agree to phase-in changes to the original rate differential of $.04 per Dth as follows: $0.10 per Dth for 2019, $0.135 per Dth for 2020, and $0.17 per Dth for 2021, and $0.18 per Dth for 2022.[737]

GTN argues that the Commission should adopt the stipulation because it was negotiated by the stipulating parties at arms-length and the stipulation is in the public interest as it would benefit ratepayers. GTN asserts that, since the original differential was adopted, the backbone rates for noncore shippers and the rate difference between the Redwood and Baja paths have increased. Specifically, GTN asserts that the forecasted rate differential for noncore customers over the rate case period will be $0.29 per Dth for 2019, $0.27 per Dth for 2020, $0.278 for 2021, and $0.29 for 2022 (Forecasted Rate Differentials).[738]

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[735] PG&E Opening Brief at 17-9.

[736] PG&E Exh-2 at 16A-AtchA-15.

[737] PG&E Opening Brief at 17-9; *see also* Exh. JS-06.

[738] Exh. GTN/Palo Alto-1 at 17 (Table 2).

Alternatively, GTN argues that the Commission should adopt a differential that uses the Forecasted Rate Differentials mentioned above.[739] GTN argues that using either the stipulated rate differentials or the Forecasted Rate Differentials is reasonable as either would reflect "the different costs of service on the Redwood and Baja paths, accurately consider the partial integration of the PG&E gas system," and "would send correct and consistent signals to new gas supplies," among other benefits.[740] In contrast, GTN argues, retaining the existing fixed $0.04 per Dth differential would be unjust and unreasonable as it would result in "Redwood and Baja rates that are essentially equalized when compared to what they should be based on cost causation principles" and, therefore, would be "inconsistent with the longstanding Gas Accord policies upheld in D.16-06-056 rejecting equalized rates."[741]

Finally, GTN notes that, while Cal Advocates supported PG&E's proposals to retain the fixed differential, it does not oppose the stipulation.

We agree that D.16-06-056 rejected PG&E's proposal to equalize the revenue requirements for the Baja and Redwood paths.[742] In denying PG&E's request, the Commission held that creating a single rate would be inconsistent with the Gas Accord, which, among other things, adopted a backbone rate design methodology that required PG&E to provide separate revenue requirements for each backbone pipeline path.

We find that the stipulation is reasonable in light of the record. The rate differential proposed in the joint stipulation is a more accurate reflection of the

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[739] *Id.*

[740] GTN Opening Brief at 4.

[741] *Id.* at 5.

[742] *See* D.16-06.56 at 301-302.

rate differences between the Baja path and Redwood path rates than the existing differential. No party opposes the stipulation. Accordingly, we adopt the rate differential in Joint Stipulation-06.

### 13.3. Local Transmission

#### 13.3.1. PG&E's Proposal

Based on the results of its Local Transmission Study (LTS), PG&E proposes to change its local transmission cost allocation approach from using a cold-year-coincident-peak demand forecast (coincident peak) to an average of cold-year and average-year-winter-season demand forecast (average winter season).[743] PG&E states that it performed the study to comply with D.16-06-056 (2015 GT&S rate case), which directed PG&E to provide in the next rate case an analysis "demonstrating whether local transmission costs should be allocated more equitably by accounting for actual relationships between pipeline capacity, throughput and costs."[744]

To comply with the directive, PG&E states that it built a hypothetical local transmission system for each customer class: core and noncore. Each hypothetical system was designed to serve "exclusively one or the other customer [class]."[745] PG&E states that it was unable to use its actual transmission system to calculate the construction costs for each customer class because the system was built to serve all of its customer classes. PG&E modeled the hypothetical systems from two (the North Bay and East Bay systems) of its twelve local transmission systems,[746] as modeling all of its local transmission

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[743] Exh. PG&E-2 at 16A-10.

[744] *Id.* at 16A-7 (citing D.16-06-056, Ordering Paragraph 38).

[745] Exh. PG&E-11, WP 10-36 at 2.

[746] Exh. PG&E-11, WP 10-36 at 2.

systems would be "impractically labor-intensive."[747] PG&E asserts that when the two systems are combined, the CWD load ratio by customer class approximates the system-wide customer class ratio.

PG&E designed each hypothetical system to meet the specific requirements of each customer class. The hypothetical local transmission system for core customers was designed to meet load requirements on an APD, to curtail all noncore customers, and exclude the lengths of pipe that exclusively served noncore customers. The hypothetical local transmission system for noncore customers was designed to meet load requirements on a cold-winter-day and excluded the lengths of pipe that exclusively served core customers.[748]

PG&E estimated the costs of constructing each hypothetical local transmission system using parametric cost curves that included the cost for engineering, drawings, permits, materials, mobilization, excavation, construction, fill, paving, demobilization, inspection, and environmental mitigation. PG&E states that these estimates were "highly generalized."[749] PG&E's states that the LTS demonstrates that it should allocate 62 percent of its local transmission costs to core customers and 38 percent to noncore customers, a result that is similar to its current cost allocation methodology (*i.e.*, 68 percent to core customers and 32 percent to noncore customers).[750]

So that PG&E can apply the results of the study to the throughput forecasts used in subsequent rate cases, PG&E states that it developed throughput allocation factor (Proxy Allocation Factor). PG&E asserts that the

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[747] PG&E Opening Brief at 17-10.

[748] Exh. PG&E-11, WP 10-36 at 3, 4.

[749] *Id.*, WP 10-36.

[750] PG&E Opening Brief at 17-11; Exh. PG&E-11, WP 10-36 at 7.

throughput methodology that resembled the results of the LTS is the average winter season demand; thus, for subsequent rate cases, PG&E proposes to use that method to allocate its local transmission cost.

In sum, for the instant rate case, PG&E proposes to allocate transmission costs based on the results of the LTS (*i.e.*, 62 percent for core customers and 38 percent for noncore customers).

#### 13.3.2. Intervenors

Several interveners argue that the LTS is flawed. First, Calpine and NCGC argue that, because the LTS uses two independent, standalone local transmission systems for each customer class, it is not representative of how PG&E's local transmission system operates.[751] Calpine argues that using a methodology that is inconsistent with the design and operation of the transmission system being studied is unprecedented as no other utility has taken that approach.[752] Moreover, Calpine argues, the combined hypothetical local transmission systems are larger than PG&E's actual local transmission system; thus, PG&E's LTS has overstated the gas flow capacity and miles of pipe.[753] Calpine argues that excess costs associated with the larger transmission system have been assigned to noncore customers as the LTS assumes that on an APD, core customers would receive service for their full demand and noncore customers would receive service for their full CWD demand.[754] However, Calpine argues, that assertion is inaccurate as on a day with abnormal peak demand, PG&E would curtail 19

[751] Calpine Opening Brief at 81; NCGC Opening Brief at 15.

[752] *Id.* at 80.

[753] Calpine Opening Brief at 82.

[754] *Id.* at 82.

percent of noncore customer load. Thus, the LTS attributes cost to noncore customers for services that the noncore customers do not receive.[755] In addition, NCGC argues that, by overbuilding the system, PG&E does not account for the back-up capacity that it uses to meet reliability obligations to core customers.[756]

Similarly, Indicated Shippers argues that PG&E's assertion that the LTS is designed to treat both hypothetical systems equally is inconsistent with the actual design of its local transmission system in that core customers receive a higher priority of service than the noncore customers.[757]

Second, Indicated Shippers contends that the design of the hypothetical systems is flawed and that PG&E's construction estimates were not verified by the parties. Indicated Shippers argues that PG&E's decision to use its East Bay and North Bay local transmission system focused on the mixture of customer class and geographic coverage, rather than more appropriate factors such as load or relevant costs for land and land rights.[758] Indicated Shippers argues that PG&E's use of pipe diameter to determine the system costs for each hypothetical system is inappropriate. Specifically, Indicated Shippers asserts that PG&E used a pipeline unit cost tool to determine the construction costs, even though PG&E acknowledged that construction costs are approximately the same regardless of pipe length or diameter.[759] Indicated Shippers assert that, PG&E stated that its

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[755] *Id.* at 83.

[756] NCGC Opening Brief at 16.

[757] Indicated Shippers Opening Brief at 50.

[758] Indicated Shippers Opening Brief at 50.

[759] *Id.* at 51.

construction estimates were "highly generalized" and neglected to allow the parties to review the itemized costs amounts.[760]

Calpine argues that, if the Commission accepts the results of the LST, it should reject PG&E's proposal to adopt the Proxy Allocation Factor. Calpine argues that the factor was "backed into" by PG&E and, similarly, Indicated Shippers argues that PG&E reversed engineered the Proxy Allocation Factor using unrelated cold year and average year forecasts, rather than a cost model that evaluated actual system peak demand and load. Several intervenors assert that PG&E admitted that the throughput values used by the Proxy Allocator show a trend of "declining percentage of core throughput relative to non-core throughput starting in 2019;" therefore, PG&E agreed that there is no assurance that the Proxy Allocation Factor will continue to track the LST in next GT&S proceeding.[761] In addition, Indicated Shippers asserts that PG&E also admitted that that there were no intrinsic features making the Proxy Allocation Factor superior to the existing methodology.[762] Indicated Shippers argues that the Proxy Factor is inconsistent with the LTS as the LTS designs load using CWD for noncore and APD for core, yet the Proxy Allocation Factor uses the average winter season.

Accordingly, Calpine argues that the Commission should require PG&E to use the allocation methodology from the previous GT&S proceeding. NCGC

[760] *Id.* at 32.

[761] Calpine Opening Brief at 84; Indicated Shippers at 54; NCGC Opening Brief at 17.

[762] Indicated Shipper Opening Brief at 54.

asserts that PG&E has stated that it does not object to using the methodology that it used in the previous rate case as there are no identified deficiencies with it.[763]

Alternatively, Calpine argues that the Commission should adopt Calpine's local transmission cost allocation methodology.[764] Calpine explains that its analysis is based on developing a transmission system that is first designed to meet the abnormal peak demand of core customers and then adds incremental capacity to meet the CWD demand of noncore customers.[765] Calpine argues that its methodology is more consistent with how PG&E's transmission system is designed and, therefore, more closely approximates the size and cost of PG&E's local transmission system than the LTS.[766]

Using its methodology, Calpine argues that PG&E can either assign 100 percent of the incremental cost to provide full CWD services to noncore customers or assign to core customers 100 percent of the costs for the original system costs minus the excess incremental capacity.[767] Calpine asserts that the average of these two methods results in assigning 76 percent of local transmission costs to core customers and 24 percent to noncore customers.[768] Calpine argues that its approach is fair because PG&E's local transmission system was designed for core customers, with noncore customers receiving the excess capacity that is not being used by core customers.[769] Calpine argues that

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[763] NCGC Opening Brief at 15-16.

[764] Calpine Opening Brief at 85.

[765] *Id.* at 85.

[766] *Id.*

[767] *Id.* at 86.

[768] *Id.*

[769] *Id.*

its approach is consistent with the cost causation principle and the capacity-based allocation approach that PG&E employs for its other GT&S transmission and storage services.[770] Indicated Shippers and NCGC support Calpine's proposal.[771]

Cal Advocates does not oppose PG&E's proposal but notes that PG&E's has not previously used hydraulic modeling to allocate local transmission costs. Cal Advocates argues that, if the Commission adopts PG&E's Proxy Allocation Factor, it should use Cal Advocates' suggested local transmission rates in Table 16A-3 of Exhibit ORA-16A.[772]

TURN and Commercial Energy support PG&E's proposal.[773] TURN argues that the LTS resolves the dispute over which throughput factor PG&E should use for allocating its local transmission costs.[774] However, similar to Calpine and Indicated Shippers, TURN questions the method in which PG&E used to develop the Proxy Allocation Factor. TURN argues that in looking for a throughput-based allocation factor, PG&E engaged in a "goal seek" process, the outcome of which does not provide an allocation factor that is superior to other approaches and may not be usable in future rate cases because the Proxy Allocation Factor shows a declining trend for core throughput through 2022.[775]

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[770] *Id.* at 87.

[771] Indicated Shippers Opening Brief at 57; NCGC Opening Brief at 18.

[772] Cal Advocates Opening Brief at 120.

[773] Commercial Energy Opening Brief at 43.

[774] TURN Opening Brief at 174.

[775] TURN Opening Brief at 173.

Accordingly, TURN recommends that the Commission adopt the results of the study (*i.e.*, 62 percent for core and 38 percent for noncore) but not the Proxy Allocation Factor.[776]

### 13.3.3. PG&E's Response

PG&E asserts that the LTS was a reasonable, good-faith response to the Commission's directive in D.16-06-056. In response to NGCG's argument that the construction costs in the LTS did not consider land costs, PG&E asserts that it would be difficult to identify the land costs for each pipeline given the volume of land records.[777] However, PG&E asserts, while it did not perform an analysis of land costs, the average pipeline costs in its model includes the cost of land and, in some instances, that issue is moot because its franchise fees provide for the right to install pipelines under publicly-owned streets.[778] PG&E also argues that the LTS did in fact account for curtailing noncore customers. PG&E explains that because it used APD for core and CWD for noncore, the LTS assigned higher local transmission rates to core customers.[779]

PG&E disagrees with intervenors who oppose the Proxy Allocation Factor. PG&E argues that, unless it uses the Proxy Allocation Factor, it will be required to perform a LST for every rate case period because throughput rates fluctuate annually.[780] Thus, PG&E argues, using the Proxy Allocation Factor is necessary to simplify future allocation changes.[781]

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[776] *Id.* at 174.

[777] PG&E Opening Brief at 17-13 to 17-14.

[778] *Id.* at 17-13.

[779] *Id.* at 17-17.

[780] PG&E Reply Brief at 17-5.

[781] *Id.* at 17-6.

PG&E opposes Calpine's alternative local transmission study. PG&E disagrees with Calpine's overall assumption that the costs associated with the class of customers who initially used the system should continue to be borne by only those customers as that assumption ignores the benefits that subsequent customers receive when they connect to the existing system. In addition, PG&E argues that Calpine's assumption is unfair to existing core customers and unsupported.[782]

#### 13.3.4. Discussion

We find that PG&E made a good-faith effort to comply with the Commission's directive. Even after recognizing that modeling the entire system would be "impractically labor-intensive," PG&E, nevertheless, attempted to do so but by using hypothetical models. Accordingly, we find that PG&E complied with the directive.

However, we find that the LTS lacks the requisite credibility to use its results to allocate local transmission costs to PG&E's core and noncore customers. The LTS uses two standalone transmission systems, based on a modified subset of PG&E's actual transmission system, that together are supposed to approximate PG&E's entire transmission system. Intervenors assert, and PG&E does not dispute, that the hypothetical transmission system is overbuilt. From this overbuilt hypothetical transmission system, PG&E derived estimates for the construction costs, which PG&E states is highly generalized and, according to intervenors, PG&E was not able to provide an itemization of the estimates for review. Thus, two of the three components that the

[782] PG&E Opening Brief at 17-6.

Commission directed PG&E to consider—that the analysis account for the actual relationship between pipeline capacity and costs—lack credibility.

In addition, using two standalone transmission systems is inconsistent with an important dynamic of PG&E's local transmission system: it is shared. In D.16-06-056, the Commission acknowledged the importance of this attribute when it rejected a request for PG&E to use the CWD demand to allocate PG&E's local transmission costs, finding that method did not "reasonably reflect the costs imposed by core and noncore customers for this shared resource."[783] Performing the study of PG&E local transmission system to determinate how to equitably assign costs to different customers classes must recognize that all customers are using a shared resources, even if some customers are not using certain components of the system, as the entire system is integrated and, therefore, interdependent. The prior cost allocation approach has been used for at least the last two rate case and continues to be just and reasonable. PG&E doesn't not oppose the prior methodology. Accordingly, we direct PG&E to continue using cold-year coincident-peak month demand method for allocating its local transmission costs.

Under PG&E's tariff, non-core customers have a lower quality of service than core customers, as service to non-core customers can be curtailed; however, in practice, non-core customers are rarely curtailed. While this practice may change, as the instant decision directs PG&E to improve its curtailment process so that it can potentially reduce the amount storage capacities required to provide the new inventory services, and PG&E's local transmission system is primarily built to meet peak demand for core customers, we find that the cost

[783] *See* D.16-06-056 at 315-316.

allocation for PG&E's local transmission service should be studied further to ensure the local transmission costs are being allocated consistent with cost causation principles. Accordingly, we direct PG&E to conduct a workshop with core and non-core customers to identify parameters for a credible transmission study. For the next rate case, PG&E shall execute the study and submit the study results as its proposal for allocating local transmission costs to ratepayers.

### 13.4. Storage Services Cost Allocation and Rate Design

#### 13.4.1. PG&E's Proposal

PG&E proposes to retain its core firm service and to add two new services: inventory management and reserve capacity.[784] As part of its core firm service, PG&E provides Parking and Lending services under schedules G-Park and G-Lend. PGE&E asserts that, except for the Parking and Lending service, it will allocate the costs of its storage services to core and noncore customers using the pro rata share of current annual injection, inventory and withdrawal cycling capacity that is assigned to each services during the rate case period.[785] For the Parking and Lending service, PG&E proposes to continue to use the maximum charge as stated in each respective tariff.[786]

PG&E's proposed storage rates are below in Table 33. PG&E did not recalculate the rates to account for the revised timeframe to comply with the DOGGR regulations. PG&E states that the Inventory Management and Reserve Capacity services will be recovered in its backbone rates.[787]

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784 PG&E Opening Brief at 17-19.

785 *Id.* at 17-19.

786 Exh. PG&E-2 at 16A-11.

787 *Id.*

**Table 33—Storage Service Rates**[788]

| Line No. | Storage Service | Usage Unit | 2019 January | 2019 April | 2020 January | 2020 April | 2021 January | 2021 April | 2022 January | 2022 April |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Core Firm Storage (GCFS) | | | | | | | | | |
| 2 | Reservation Charge | ($/Dth/ Month) | $0.3962 | $0.4792 | $0.5456 | $0.5471 | $0.7709 | $0.7731 | $0.6695 | $0.6733 |
| 3 | | | | | | | | | | |
| 4 | Reservation Charge | ($/Dth/ Month) | $0.5367 | Service no longer offered under proposed NGSS | | | | | | |
| 5 | Negotiated Firm Storage (G-SPS) | | | | | | | | | |
| 6 | Injection | ($/Dth/d) | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 |
| 7 | Inventory | ($/Dth) | $3.5541 | $3.5541 | $3.5541 | $3.5541 | $3.5541 | $3.5541 | $3.5541 | $3.5541 |
| 8 | Withdrawal | ($/Dth/d) | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 |
| 9 | Negotiated As-Available Storage (G-NAS) Maximum Rate | | | | | | | | | |
| 10 | Injection | ($/Dth/d) | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 | $5.7236 |
| 11 | Withdrawal | ($/Dth/d) | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 | $26.1629 |
| 12 | Market Center Services (Parking and Lending Services) | | | | | | | | | |
| 13 | Maximum Daily Charge | ($/Dth/d) | $1.1650 | $1.1650 | $1.1650 | $1.1650 | $1.1650 | $1.1650 | $1.1650 | $1.1650 |
| 14 | Minimum Rate (Per Transaction) | | $57.0000 | $57.0000 | $57.0000 | $57.0000 | $57.0000 | $57.0000 | $57.0000 | $57.0000 |

In addition, to account for the costs to implement the portion of the NGSS that requires PG&E to decommission Los Medanos and Pleasant Creek, PG&E proposes approximately $62 million per year in depreciation and decommissioning costs from 2019-2022. PG&E proposes to allocate the NGSS depreciation and decommissioning costs based on the usage of its three storage services.[789] PG&E states that the allocation breakout is as follows: 68 percent to core customers, 16 percent to noncore customers, and the remaining 16 percent to system balancing, which will be allocated to core and noncore customers on an equal cents per therm basis.[790] PG&E proposes to allocate costs to core customers

[788] Exh. PG&E-2 at 16A-13.

[789] Exh. PGE-32 at 16A-9.

[790] Exh. PG&E-32 at 16A-8; *see also* PG&E Opening Brief at 17-21.

using the distribution allocation factor established in the most recent gas distribution cost allocation proceeding.[791] PG&E argues that, using its proposal would allow the NGSS depreciation and decommissioning costs to be "recovered in end-use rates in an allocation proportional to the storage system benefits historically received by customers."[792]

Lastly, for the Self-Balancing credit that PG&E provides pursuant to the G-BAL gas rate schedule, PG&E proposes to adjust the calculation to distinguish the costs for two functions performed by its proposed Inventory Management service: intra-day balancing and monthly balancing.[793]

#### 13.4.2. Intervenors

Cal Advocates states that, pursuant to a data request, PG&E provided Cal Advocates with three cost allocation models for its storage services including "Scenario 3," which "assumes the DOGGR would allow PG&E to conduct the newly required well inspections on a risk-informed basis, rather than once every two years." Cal Advocates asserts that PG&E should adopt the storage rates that Cal Advocates calculated "based on Scenario 3 assumptions in the model run."

TURN disagrees with PG&E's assertion that its proposal for allocating the NGSS depreciation and decommissioning costs represents an allocation in proportion to the benefits "historically" received by customers. TURN argues that PG&E's proposal is based on the last two rate cases. TURN proposes two alternative methodologies which, it asserts, reflects the long-term history of allocating PG&E's storage costs. In addition, TURN refers to the NGSS

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[791] PG&E Opening Brief at 17-22.

[792] *Id.* at 17-21.

[793] *Id.*

depreciation and decommissioning costs as "storage transition cost," and asserts that such cost should be allocated based on "the history of how those costs would have been recovered," but for "the Aliso Canyon incident and subsequent DOGGR regulations;" said another way, as if the DOGGR regulation had not be enacted.

First, TURN argues that the NGSS depreciation and decommissioning costs should be allocated based on cold-year-winter-season (CYWS) throughput. This allocation method would assign 63.5 percent to core and 36.6 percent to noncore, while PG&E's proposal would allocate 73.8 to core customers and 26.2 percent to noncore. TURN argues that allocating additional costs to noncore customers is consistent with the Commission's fuel-based allocation approach, which it used prior to adopting the costs-based rates that were established in D.86-12-009.

Second, as an alternative to using CYWS throughput, TURN argues that the NGSS depreciation and decommissioning costs should be allocated to all customers on PG&E's backbone system, including off-system customers, rather than only end-use customers. While TURN admits that "it is difficult to specify exactly what portion of PG&E's historic storage capability directly benefited backbone transmission service customers," it recommends allocating one-third of the NGSS depreciation and decommissioning costs to all backbone customers and the remaining two-thirds to end-use customers.

So that the allocation of NGSS depreciation and decommission costs to end-use rates accounts for the use and benefits of the storage facilities when storage was still a bundled service, TURN recommends that 60.8 percent to core customers, 24.7 percent to noncore, and 14.5 percent for system balancing.

### 13.4.3. Discussion

We find that PG&E's proposed rate design and cost allocation for its storage services (*i.e.,* core firm, standard firm, and monthly balancing) are just and reasonable, subject to the updates necessary to reflect the final DOGGR compliance requirements. PG&E's allocation methodology—pro rata share of annual injection, inventory and withdrawal cycling capacity that is assigned to each service during the rate case period—was adopted by the Commission in the two preceding rate cases.[794] With the exception of the rate differential, which is discussed in section 13.2, no party protests PG&E's backbone rate design.

We find that PG&E's proposed allocation of the NGSS depreciation and decommissioning costs is just and reasonable. PG&E's proposal will provide rate recovery by allocating the depreciation and decommissioning costs for Los Medanos and Pleasant Creek to those customers who use the services that the storage fields provide. PG&E will allocate the NGSS depreciation and decommissioning costs in a manner consistent with the extent to which each customer class uses the respective services.

We are not persuaded by TURN that the allocation of the NGSS depreciation and decommissioning expense should consider the history of the storage facilities such that it reflects how the cost would have been recovered, absent the Aliso Canyon incident and subsequent DOGGR regulations. While the DOGGR regulations, in part, triggered the NGSS, PG&E's cost allocation methodology has been in place for at least the last two rate case cycles. Thus, but for the NGSS, PG&E's existing cost allocation methodology would have continued until the end of useful life of each storage field (Los Medanos and

[794] PG&E Opening Brief at 17-19 to 17-23.

Pleasant Creek) and, therefore, the related cost would have been borne by customers in the same manner reflected in PG&E's proposal for allocating the NGSS depreciation and decommissioning expense.

Moreover, we find that both of TURN's recommendations are deficient. TURN bases its recommended approach—that PG&E use CYWS throughput as a basis for allocating the NGSS depreciation and decommissioning costs—on a method that predated the Commission's decision adopting cost-based rates in 1986 and, therefore, is outdated. Similarly, TURN's alterative option is outdated as it proposes to allocate NGSS depreciation and decommissioning costs to end-use customers using an allocation methodology that was effective when PG&E was providing bundled storage service. Moreover, TURN was not able to offer a method to identify, using quantifiable evidence, the amount of NGSS depreciation and decommissioning costs that PG&E should allocate to backbone customers.

Lastly, we find that PG&E's proposals to continue using the maximum charge in its tariff for the Parking and Lending Service and to revise its Self-Balancing credit to distinguish between the two Inventory Management service functions are just and reasonable. The maximum charge is currently in the Parking and Lending tariff and no party asserts that it is unjust or unreasonable. The revisions to the Self-Balancing credit are necessary to account for the two separate functions that the new Inventory Management service will provide to PG&E's customers.

## 14. Other Ratemaking Issues

### 14.1. On-System Throughput Demand and Revenue

PG&E states that it forecasted throughput demand for each market segment: core, noncore industrial, noncore electric generation, and wholesale.

To forecast throughput demand for these segments, PG&E states that it used econometric modeling,[795] which is the same approach that it used in its 2018 Gas Cost Allocation Proceeding. PG&E asserts that, except for the market responsive Electric Generation customers, it and the Cal Advocates reached a stipulation regarding the throughput forecast. The stipulation is below in Table 34.

**Table 34—Stipulated Throughput Forecast[796]**
**(MDth/d)**

| **Category/Year** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|
| Residential | 507 | 500 | 496 | 493 |
| Small Commercial | 213.5 | 213 | 212.5 | 213 |
| Large Commercial | 19 | 18.5 | 18.5 | 18.5 |
| Interdepartmental | 0.4 | 0.4 | 0.4 | 0.4 |
| Core NGV | 8 | 9 | 9 | 10 |
| Total Core | 747.5 | 740.5 | 737 | 734.5 |
| Non Core Industrial Distribution | 71 | 71 | 71 | 71 |
| Industrial Transmission, Backbone & NGV | 496 | 491 | 497 | 505 |
| Non Market EG | 175 | 175 | 175 | 175 |
| Market EG | - | - | - | - |
| Total Non Core (2) | 973 | 961 | 963 | 974 |
| Wholesale | 10 | 10 | 10 | 9 |
| **Total Volumes** | **1,731.5** | **1,712.5** | **1,710** | **1,717.5** |
| (2) These totals include assumed numbers for Market EG, but are not intended to preclude a different Market EG throughput. | | | | |

[795] Econometric Models uses historical data to analyze the relationships between economic and demographic data, prices, temperature, and seasonal-use patterns.

[796] Exh. JS-04.

**Table 35 – Stipulated Throughput Forecast – Cold Year**[797]

| **Category/Year** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|
| Residential | 572 | 564 | 560 | 557 |
| Small Commercial | 229.5 | 229 | 228.5 | 229 |
| Large Commercial | 19.5 | 19 | 19 | 19 |
| Interdepartmental | 0.5 | 0.5 | 0.4 | 0.4 |
| Core NGV | 8 | 8 | 9 | 10 |
| Total Core | 829 | 822 | 818.5 | 816 |
| Non Core Industrial Distribution | 73 | 73 | 73 | 73 |
| Industrial Transmission, Backbone & NGV | 496 | 491 | 497 | 505 |
| Non Market EG | 175 | 175 | 175 | 175 |
| Market EG | - | - | - | - |
| Total Non Core | 976 | 964 | 966 | 976 |
| Wholesale | 11 | 11 | 11 | 11 |
| **Total Volumes (3)** | **1,816** | **1,797** | **1,794.5** | **1,803** |
| (3) These totals include assumed numbers for Market EG, but are not intended to preclude a different Market EG throughout. | | | | |

With respect to Market Responsive Electric Generation customers, PG&E states that their output is influenced by wholesale electricity market prices. As such, PG&E states, to forecast demand, it used the MarketBuilder program, which is an economic equilibrium program.[798] PG&E asserts that, even though it used historical demand from 2011 to 2017 to confirm the accuracy of the model, it believes that "there is potentially bias in the model."[799] PG&E's demand forecast for Market Responsive Electric Generation customers is below in Table 35A.

[797] *Ibid.*

[798] PG&E Opening Brief at 17-2.

[799] *Id.* at 17-3.

**Table 35A – Electric Generation Forecast,[800]**
**Market Responsive Electric Generation Gas Demand**

| Line No. | MDth/d | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| 1 | Local Transmission | 52 | 50 | 48 | 50 |
| 2 | Backbone-Only | 179 | 175 | 172 | 173 |
| 3 | Total | 231 | 224 | 220 | 223 |

### 14.1.1. Intervenors

TURN argues that PG&E's forecast for Market Responsive Electric Generation customers is understated. TURN asserts that PG&E's forecast of Electric Generation demand for the last five months in 2017 is 24 percent lower (154 MDth/d) than the actual amount of gas that Electric Generation customers demanded during that timeframe. Similarly, TURN asserts, PG&E's forecast is consistently 14 percent lower (98 MDth/d) than the actual demand.[801] TURN asserts that PG&E acknowledged that the model has problems but stated that it "is not quite sure of a proper adjustment."[802] Accordingly, TURN request that the Commission direct PG&E to adjust its forecast by 98 MDth/d for each day in the rate period.[803]

NCGC disagrees with TURN's contention and argues that PG&E's Electric Generation throughput should not be based on market conditions that existed in 2017.[804] However, if the Commission determines that the forecast for Electric

[800] PG&E Opening Brief at 17-2, Table 17-1.

[801] TURN Opening Brief at 163-169.

[802] *Id.* at 168 (citing 8 RT 850 (Graham/PG&E)).

[803] *Id.* at 168.

[804] NCGC Opening Brief at 13-16.

Generation throughput should be revised, NCGC argues that the adjustment should be limited to the amount that PG&E has identified (*i.e.*, 54 MDth/d).[805]

TURN also asserts that PG&E's forecast of Market Response Electric Generation customers is the same for an average temperature year as for a cold year. TURN asserts that PG&E acknowledged that it did not prepare a cold-year forecast for various reasons, including that electric generation demand is mostly influenced by hot temperatures and that cold temperatures are less impactful.[806] TURN disagrees with this contention and argues that, because all-electric homes, among other devices, increase their usage under colder than average temperature conditions, PG&E should expect that gas generation demand could also increase. Accordingly, TURN requests that the Commission direct PG&E to include in its next GT&S rate case application a sperate cold-year Electric Generation demand forecast.[807]

#### 14.1.2. PG&E Response

PG&E attributes the discrepancies between the model data and the historical data to its inability to forecast when a gas generator in its territory will be selected for dispatch, given the competitive nature of the wholesale energy market. Thus, PG&E argues that, notwithstanding the forecast discrepancies, the MarketBuilder provides a reasonable forecast of Electric Generation demand. However, it asserts, if the Commission agrees with TURN's contention that the forecast should be adjusted, PG&E argues that the upward adjustment should be

[805] *Id.* at 10-12.

[806] TURN Comment on Proposed Decision at 17 (referencing TURN Data Request No. 10, Question 2).

[807] TURN Comment on Proposed Decision at 18.

consistent with the margin of error between the model and the historical data over the last 12 months, which is 54 MDth/d.[808]

#### 14.1.3. Discussion

We find that stipulated forecast for throughput demand for all customers, except for the market responsive Electric Generation customers, is reasonable in light of the record. PG&E used a methodology that was consistent with the 2018 Gas Cost Allocation Proceeding and adjusted its results to reflect the agreement between it and Cal Advocates. No party protested the forecast. Accordingly, we adopt stipulated forecast in Exh. JS-04, as adjusted to correct rounding errors.

For the demand forecast for Market-Responsive Electric Generation customers, we find that PG&E's description of the forecasting discrepancies is reasonable. We agree with TURN's contention that such discrepancies should be resolved by adjusting the forecast using historical demand data as a baseline. However, given that PG&E attributes the forecasting discrepancies to the unpredictability of the energy markets, we find that the adjustment should be based on the most recent year of data, rather than the average of the 52-month period starting in 2011. Accordingly, we direct PG&E to increase its forecast demand for Market Responsive Electric Generation by an annual daily average of 54 MDth/d for every day.

We agree with TURN's contention that PG&E should include in its next GT&S rate case application a sperate cold-year Electric Generation demand forecast. In addition to reasons that TURN articulates, we find that the increase

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[808] PG&E Reply Brief at 17-1.

use of electric vehicles could also impact the Electric Generation demand forecast when temperatures are colder than normal.

### 14.2. Off-System Transmission Revenues

PG&E states that its demand forecast for off-system transmission revenue represents the amount of gas that will be transported though PG&E's backbone system to pipelines that will deliver gas to customers located outside of PG&E's service area.[809] PG&E states that its off-system transmission revenue is derived from long-term rate schedule G-XF contracts and negotiated firm and as-available contracts. PG&E asserts that the forecast for negotiated firm and as-available contracts is $9.53 million for 2019-2021 and $17.03 million for 2022.[810] PG&E asserts that, because the G-XF contracts have a fixed rate design and known volumes for the rate case period, the forecasted demand for C-XF contracts is $86 million for 2019-2022.[811]

We find that PG&E's forecast for off-system transmission revenues is just and reasonable. We note that no party protested the forecast. Accordingly, we adopt PG&E's 2019-2022 forecast for off-system transmission revenues.

### 14.3. Transmission Level Customer Access Charge (CAC)

On a monthly basis, noncore end users pay a transmission-level CAC. PG&E developed its proposed CAC charges for the rate case period using the same methodology that it proposed in its 2015 GT&S application.[812] Going forward, however, PG&E proposes to calculate the CAC using a combination of

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[809] Exh. PG&E-1 at 16C-2.

[810] PG&E Opening Brief at 17-5.

[811] Exh. PG&E-1 at 16C-13, 16C-20.

[812] Exh. PG&E-2, Table 16A-5.

its GT&S and GRC revenue requirements. PG&E also proposes to submit the next CAC during its Gas Cost Allocation Proceeding.[813]

We find that PG&E's CAC rates are just and reasonable. No party opposes PG&E's CAC methodology or rates.

### 14.4. Electric Generation Rate Design

The backbone transmission system transports gas from PG&E's interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission system and distribution system. The local transmission system accepts gas from the backbone and transports it to the distribution system only.

Under its current tariffs, PG&E offers two separate gas transmission rates for Electric Generation (EG) shippers: (1) EG shippers that connect directly to the PG&E backbone system pay the EG Backbone transmission rate; and (2) EG shippers that connect to the local transmission system pay the EG Local Transmission rate.[814] The EG local transmission rate covers the additional service to connect electric generation located more remotely from the Backbone system, while the EG backbone transmission rate does not include local transmission costs. PG&E does not propose changes to the EG Rate Design.[815]

As discussed above PG&E uses cold-year coincident-peak month demand method for allocating its local transmission costs between core and non-core customers, which include EG customers.

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[813] PG&E Opening Brief at 17-24.

[814] *See* D.16-06-056 at 320.

[815] PG&E Opening Brief at 17-24.

#### 14.4.1. Intervenors

Some intervenors assert that some of the cost components of PG&E's EG local transmission rates design should fixed, rather than variable based on coincident peak month demand. Because the transmission rates under the current rate design varies each month, California Independent System Operator's (CAISO) energy market bidding rules considers such cost as variable transportation costs that generators are required include to include in the bids that they submit to be considered for dispatch. Intervenors argue that reducing the variable gas transportation costs will reduce the associated bid price, which in turn will (1) reduce the market clearing prices in the CAISO energy market and (2) allow EG local transmission customers to compete with EG backbone customers for dispatch awards.

NCGC conducted a study to evaluate the impact that the existing rate design has on the ability of EG local transmission generators to win dispatch awards in CAISO's energy markets. Based on its study, NCGC concluded that a uniform EG backbone and EG local transmission rate will result in the most efficient dispatch of the gas-fired generators and the least uplift in the CAISO market.[816] Accordingly, NCGC proposes to change the manner in which EG local transmission customers pay their share of PG&E's revenue requirement.

Specifically, NGCG proposes to establish a fixed revenue requirement cap with the exception of the costs for certain fees, such as the Commission Fee, which would continue to be based on the monthly forecasted usage rates. The

[816] NCGC Opening Brief at 25.

fixed revenue requirement cap would be determined for the each "facility in the rate class."[817]

TURN proposes a similar design, with the exception of the calculation of the fixed cost component. Under TURN's proposal, PG&E will fixed transmission costs by multiplying the base local transmission revenue requirement allocated to the EG local transmission class by each EG local transmission customers' percentage share of recorded throughput for EG local transmission service from 2015-2017.[818] TURN also argues that PG&E's local transmission costs are generally fixed; thus, the rate design should be revised to reflect that. NCGC argues that TURN's proposal could harm EG local transmission facilities if the throughput forecast for the rate class is significantly overstated. NCGC also argues that TURN's proposal should be revised to include a credit mechanism that refunds a portion of the fixed payment when a customer is curtailed.[819]

Calpine opposes the proposals to revise PG&E's EG local transmission rate design. Calpine argues that NCGC's proposal would create an unfair subsidy by shifting local transmission costs from local transmission customers to backbone customers, an outcome the Commission has repeatedly determined to be unjust and unreasonable.[820] Calpine asserts NCGC's proposal would increase the likelihood that PG&E will under-collect its revenue requirement. Calpine explains that the revenue cap would limit PG&E's ability to recover during a dry year when EG throughput is high and that PG&E would not be able to

[817] NCGC Opening Brief at 26.

[818] TURN Opening Brief at 181-188.

[819] NCGC Opening Brief at 48-50.

[820] Calpine Opening Brief at 93-99.

over-recover during a wet year to make up the difference. Said another way, the revenue cap would prevent over-collections against a forecast but allow under-collections against a forecast. Thus, because PG&E has a balancing account for local transmission under-collections, a portion of the shortfall would be allocated to some of PG&E's EG backbone customers.

Calpine also argues the NCGC's and TURN's proposals are incomplete because they offer multiple options for the rate design components that they seek to change and fail to offer a solution to the cost shifting issue.[821] Accordingly, Calpine argues that implementing either of the proposals would require further evaluation in another proceeding. SMUD also argues that NCGC's study is flawed because it (1) is not based on an adequate sample size of representative generators,[822] and (2) fails to demonstrate that the EG local transmission rate design is preventing EG local transmission customers from being dispatched,[823] among other issues.

SMUD agrees that if a bid that has a higher price is selected, it may result in a higher electric rate; however, SMUD argues, this outcome is not a flaw because that is how CAISO's market is designed to function. SMUD explains that, because an EG local transmission customer does not own the local transmission line, it rents capacity on PG&E's local transmission system and pays a usage-based volumetric transportation rate that is appropriately considered a

[821] Calpine Opening Brief at 102.

[822] The Study uses 3 generators that NCGC selected based on its familiarity with the facility rather than using a statistical sample. (SMUD Opening Brief at 14-15.)

[823] The study failed to consider alternate causes for a lower dispatch rate, such as the possibility of outages at the three plants in the study or that a generator could have been displaced by lower-cost renewable resources, which underwent a significant expansion in installed capacity during the same period as the study. (SMUD Opening Brief at 18.)

variable cost.[824] SMUD argues that providing accurate variable cost information is necessary for CAISO's market structure to function property because CAISO's market relies on a correct estimates of incremental costs, such as variable costs, to identify the least-cost dispatch solution. Accordingly, SMUD suggests that NCGC should use CAISO's shareholder process to seek revisions to how CAISO uses volumetric gas transportation costs to calculate incremental costs.[825]

In addition, SMUD argues that NCGC's proposal would unfairly benefit EG local transmission customers because EG backbone customers would still need to include variable costs for EG backbone transmission service in their bids. Thus, EG local transmission customers would not have to make the corresponding capital investments, long-term commitment and assumption of risk that EG backbone customers are required to make.[826]

SMUD also argues that PG&E's balancing and memorandum accounts for this program should be revised so that EG backbone customers are not allocated costs for PG&E's local transmission system. To resolve this issue, SMUD recommends that the Commission direct PG&E to 1) separately track cost related to PG&E's local transmission system for all GT&S-related balancing and memorandum account that are recovered from EG backbone customers and 2) assign all local transmission-related costs recorded to GT&S-related balancing and memorandum accounts to the Noncore Customer Class Charge Account.[827]

Dynegy opposes TURN's and NCGC's proposals. Dynegy argues that a capped fixed cost would require a generator to risk that its revenue will cover its

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[824] SMUD Opening Brief at 10-12.

[825] *Id.* at 28.

[826] *Id.* at 29.

[827] SMUD Opening Brief at 7.

allocate share of transmission costs, a risk that the current design does not require as a generator is only responsible for local transmission costs when it is dispatched. Dynegy argues that some generators could retire.[828]

#### 14.4.2. PG&E Response

PG&E argues that NGCG's assertion—that a uniform EG backbone transmission and local transmission rates will result in the most efficient dispatch of the gas fleet and the least uplift in the CAISO market—is faulty. To identify the least-cost dispatch solution, CAISO's bidding process dispatches generation based on incremental costs. Because NCGC's proposal would exclude a portion of an EG local transmission customer's gas transportation costs, the least-cost generator may not be dispatched. Accordingly, when bidding into CAISO's energy markets, PG&E argues, the incremental costs (which includes variable costs) for backbone and local transmission generators must be priced appropriately.[829]

PG&E asserts that TURN's proposal "may be workable, but PG&E does not believe it is sufficiently developed to warrant adoption by the Commission at this time." PG&E states that the outstanding issues include: how to set an equitable fixed fee obligation for each generator and how to account for the variability of the market.[830]

With respect to SMUD's contention regarding the allocation of EG local transmission cost to EG backbone customers, PG&E argues that it allocates cost to customers according to its tariffs and the decisions that have been approved

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[828] Dynegy Opening Brief at 19-20.

[829] PG&E Opening Brief at 17-27.

[830] PG&E Opening Brief at 17-8.

by the Commission. PG&E explains its process of transferring balancing account information into rates and states that Commission's Energy Division audits PG&E's balancing accounts. PG&E asserts that, in response to its AGT, SMUD raised similar arguments in its November 27, 2018 protest, but that the Commission approved PG&E's filing, without proposing modifications.[831]

#### 14.4.3. Discussion

We continue to find that PG&E's existing methodology for calculating different rates for EG backbone and EG local transmission customers is just and reasonable because PG&E's EG backbone transmission customers do not use "the local transmission system, and do not cause local transmission costs to be incurred. Such customers should not be forced to pay the costs of a local transmission system which they do not use, thereby subsidizing EG units located on the local transmission system that are more costly to serve."[832]

With respect to the rate design for the EG local transmission rate, we find that NCGC and TURN have not demonstrated that the existing design is unjust and unreasonable. Both parties argue that the rate design should be changed to (1) reduce the market clearing prices in the CAISO energy market, and (2) allow EG local transmission customers to compete with EG backbone customers for dispatch awards. The Commission has repeatedly explained why the second argument concerning competition is inconsistent with ratemaking principles, including cost causation, as the cost for these services are different and, therefore, should not be equalized, so we will not revisit this issue here.

[831] PG&E Opening Brief at 16-5 to 16-7.

[832] D.16-06-056 at 327-328.

We find, however, that the issue concerning participation in CAISO's energy markets may warrant consideration. Intervenors argue that the rate design could cause CAISO to dispatch EG facilities based on a bid that includes a high transportation costs, thereby causing electric prices to be higher.[833] PG&E and other parties demonstrate that the dispatch process is designed to select EG facilities using, among other factors, marginal costs, which includes variable costs. Thus, the opposing parties argue that the fact that a higher variable cost, such as gas transportation costs, could drive up electricity prices is a natural occurrence of the market, and some argue that using artificially low variable costs could in fact drive up energy prices. Yet TURN argues that PG&E's local transmission costs are primarily fixed.

We find that, to the extent that PG&E's revenue requirement is considered a fixed cost in the CAISO energy market, further review of the proposals to revise the EG local transmission rate design is warranted. Parties who both oppose and support the proposals all assert that there is a positive correlation between the variable cost of a bid and electricity prices. Thus, requiring consumers to pay a higher electricity rate based on a conflict in how a just and reasonable rate is nevertheless interpreted in CAISO's market rules could be a short-sighted approach to ratemaking. Moreover, PG&E states that the "general concept" of NCGC's proposal, as revised by TURN, "is workable, but PG&E

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[833] NCGC also argues that the rates should be equalized to help EG local transmission customers compete with EG backbone customers. This contention as be raised and answered in prior proceedings, so we will not address that issue again here. *See* D.16-05-056 at 326-330, petition for modification denied, D.18-02-003; *see also* D.03-12-061, as modified by D.04-05-061 at 20.

does not believe [the concept] is sufficiently developed to warrant adoption by the Commission at this time.[834]

Accordingly, we find that a workshop hosted by the Commission's Energy Division should be convened to further refine TURN's proposal or identify new proposals to modify the EG local transmission rate design, as discussed above.[835] In setting the parameters for the workshop discussion, Energy Division may use the conditions that SMUD suggests,[836] or other conditions. If the majority of the workshop attendees and Energy Division and PG&E agree on a proposal,[837] we direct PG&E to consult with CAISO to confirm that the identified proposal will not distort or allow gaming of CAISO's bidding and dispatch processes. If the proposal is permitted under CAISO's market rules, PG&E shall submit the proposal using the Commission's Tier 3 Advice Letter process.

With respect to the balancing and memorandum account issue raised by SMUD, PG&E does not refute that EG backbone customers are allocated costs for EG local transmission costs. As discussed, we find that local transmission costs should not be allocated to EG backbone customers. Accordingly, we direct PG&E to file a Tier 2 Advice Letter proposes to either use SMUD's two-step proposal or implement an alternative process.

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[834] PG&E Reply Brief at 17-8.

[835] Follow-up workshops shall be conducted as deemed necessary by the Energy Division.

[836] SMUD Comments to Proposed Decision at 8-9.

[837] In identifying a proposal, the workshop attendees may use the criteria outlined in SMUD's comments to the PD or different criteria. SMUD Comments on Proposed Decision at 7.

### 14.5. Cost Recovery Mechanisms

PG&E proposes to retain the balancing accounts to recover core revenue requirements and its Tax Act memorandum account.[838] PG&E proposes to modify the Core Fixed Cost Account and the Noncore Customer Class Charge Account (NCA) to recover the revenue requirement associated with depreciation and decommissioning of Los Medanos and Pleasant Creek Storage Facilities from all customers in end-use rates.[839]

PG&E proposes to modify the Balancing Charge Account to record the purchase and sale of gas from its storage fields and the purchasing and selling of spot gas to for its proposal to address minim flow requirements on the Baja path. PG&E proposes to establish a new memorandum account to track and record incremental costs to comply with any new federal or state regulation or rule that is issued between GT&S funding cycles for which PG&E has not been able to incorporate a forecast of costs into a rate case and which are not already addressed and recorded in another account.

PG&E proposes to discontinue the Hydrostatic Pipeline Testing memorandum account. This account was established by the Commission in D.16-06-056 to allow PG&E to recover costs above the authorized forecast. PG&E dis not exceed the authorized forecast; thus, it seeks to discontinue the memorandum account.[840] PG&E also proposes to discontinue the Hydrostatic Station Testing Memorandum Account because it incorporated the forecast for hydrostatic station testing in the instant application. In addition, PG&E proposes

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[838] PG&E Opening Brief at 16-15 to 16-16.

[839] *Id.* at 16-17.

[840] *Id.* at 16-19 to 16-20.

to discontinue the Tax Normalization Memorandum Account, which was established to track expenses related to an IRS ruling that has since been issued.[841]

We find the PG&E's proposals to retain, change or discontinue these accounts are just and reasonable. No party protests PG&E's proposals.

#### 14.5.1. Gas Storage Balancing Account

This issue is discussed in section 6, concerning the Storage Asset Family.

#### 14.5.2. Transmission Integrity Management Program

This issue is discussed in section 8, concerning the Transmission Pipeline Asset Family.

#### 14.5.3. Local Transmission Costs

This issue is discussed in section 14, concerning Other Ratemaking Issues.

#### 14.5.4. Gas Transmission and Storage Revenue Sharing Mechanism

PG&E's GT&S revenue requirements are allocated between core and noncore customers. Gas Transmission and Storage Revenue Sharing Mechanism (GTSRSM) tracks annual revenue over- and under- collections and shares them between customers and PG&E's shareholders as follows: 1) noncore backbone and core backbone usage over-and under-collections are allocated to 50 percent to customers and 50 percent to shareholders, 2) noncore local transmission over- and under-collections are allocated 75 percent to customers and 25 percent to shareholders. PG&E stated that it is also required to provide $30 million in seed value.

[841] PG&E Opening Brief at 16-23.

PG&E proposes to change the GTSRSM by 1) assigning all local transmission over- and under- collections to customers, 2) changing the backbone sharing percentages to 75 percent to customer and 25 percent to shareholders, 3) removing the $30 million seed value, (4) changing the timing of annual transfers of the balance of the GTSRSM to December 21, and (5) removing noncore storage from the GTSRSM.[842]

PG&E asserts that the changes to the local and backbone transmission allocations are consistent with California's revenue decoupling policy, which aligns utility and customer incentives to maximize energy conservation.[843]

PG&E proposes to remove noncore storage from the GTSRSM because as part of the NGSS, it plans to eliminate the Gas Schedule G-SFS, which concerns standard firm services, from its tariff. For the incidental negotiated storage revenue it receives after the NGSS is adopted, PG&E proposes to allocate those revenues to customers through end-use rates based on the core and noncore customers' proportional share of total storage revenue requirements.[844] PG&E explains that the $30 million seed value was adopted pursuant to a settlement approved in D.11-04-031 to offset PG&E's market storage revenues from its storage revenue requirement.[845] PG&E argues that the seed value no longer serves a useful purpose because NGSS will change PG&E's asset holdings and storage services, and PG&E has experienced significant market storage revenue under-collections since 2011. PG&E proposes to change the timing for the annual transfer so that it is consistent with PG&E's other balancing accounts.

[842] PG&E Opening Brief at 16-7.

[843] *Id.* at 16-8.

[844] Exh. PG&E-2 at 17B-5.

[845] *Id.* at 17B-8.

Calpine disagrees with PG&E's proposal to change the allocation for local transmission and backbone over- and under-collections. Calpine argues that in the prior rate case, the Commission rejected PG&E's similar proposals, finding that PG&E should continue to have incentives to earn its forecasted revenues, especially in markets where it competes with its customers.[846]

We are persuaded by Calpine's argument and find that the GTSRSM should remain in place, with two exceptions. PG&E's proposal to remove noncore storage is reasonable as, pursuant to the NGSS, PG&E will eliminate its standard firm storage service. We also find that PG&E's proposal to change the timing for the annual transfer to coincide with its other balancing accounts is reasonable.

#### 14.5.5. Gas Transmission and Storage Memorandum Account

Because this decision adopts the 2019 revenue requirement starting in October 1, 2019, we authorize PG&E to amortize the under-collection of its base revenue requirement that has occurred because the decision was not adopted by January 1, 2019. PG&E shall amortize the under-collection over a 15-month period, beginning on October 1, 2019, and ending on December 31, 2020. The under-collection shall be recorded in its Gas Transmission and Storage memorandum account (GTSMA). The GTSMA was authorized in D.14-06-012 and continued in D.16-06-056 so that PG&E could recover the under-collection from its 2015 GT&S rate case.

[846] Calpine Opening Brief at 69 (citing D.16-06-056 at 249-250).

## 15. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Powell in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. On August 5, 2019, ABAG Power, Cal Advocates, Calpine, CCUE, Commercial Energy, CTA Parties, Dynegy, Indicated Shippers, NCGC, OSA, PG&E, TURN, SMUD filed Comments. Reply comments were filed on August 12, 2019 by ABAG Power, Calpine, Commercial Energy, CMTA, CTA Parties, Indicated Shippers, Joint ISPs, NCGC, PG&E, TURN, SMUD. The Proposed Decision has been revised throughout to reflect the comments. With respect to the data in the Appendices, that information was revised where warranted.

## 16. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Christine A. Powell is the assigned ALJ in this proceeding.

## Findings of Fact

**General Issues**

1. PG&E submitted service disconnection data required by Section 718.
2. PG&E and Cal Advocates stipulate to using a new report template to replace PG&E's Gas Transmission and Storage Report and Transmission Pipeline Compliance Report.
3. For the new report template, Energy Division requires additional information as stated in section 3.2 of the instant decision.
4. The stipulation provides that PG&E will submit the new report on an annual basis.

5. The new report template contains pipeline transmission compliance information that is currently provided to the Commission on a quarterly basis.

6. The Commission instituted Rulemaking 13-11-006 to determine whether PG&E's GRC and its GT&S rate case should be combined.

7. The record in this proceeding does not include procedural information about PG&E's GRC.

8. PG&E's RAMP process begins during the same year that PG&E currently files its GT&S rate case.

9. The RAMP and Safety Model Assessment Proceeding use risk management tools that are more quantitative than PG&E's Risk Evaluation Tool and Risk-Informed Budget Allocation risk management tools.

**Natural Gas Storage Strategy**

10. The winter-summer gas price spread decreased from $0.715 in 2008 to $0.199 in 2017.

11. The demand in California for natural gas is generally projected to decline by 1.4 percent per year from 2016-2035.

12. In complying with the new gas regulations required by DOGGR, PG&E will lose 40 percent of its storage withdrawal capacity.

13. Replacing enough of its storage capacity to continue to provide price commodity service (hedge for winter-summer price spread) and to provide reliability service require a present value revenue requirement of $4.89 billion over 20 years.

14. For core and electric generation customers, PG&E uses a 1-day-in-10-year standard. The volume for core customers is 2,493 MMcf/d and for electric generation customers, 928 MMcf/d.

15. For industrial customers, PG&E uses an estimate of the Average daily winter demand, which is 522 MMcf/d. For Off-system and shrinkage, PG&E estimates 123 MMcf/d.

16. The 1-day-in-10-year standard for electric generation customers and core customers accounts for the higher than average heating value of the gas on PG&E's gas transmission system.

17. PG&E's proposed reliability standard is designed to ensure that PG&E provides safe and reliable gas transmission service.

18. To resolve inventory imbalance and storage issues on its pipeline system, PG&E historically drew from unused core gas inventory, which was approximately 33 Bcf.

19. With the elimination of the price commodity service, PG&E will maintain approximately 11 Bcf of natural gas at its storage fields with 5 Bcf reserved for core customers.

20. PG&E's reliability-only strategy cannot rely on stored unused core gas inventory as it will be reduced from 33 Bcf to 5 Bcf.

21. PG&E cannot rely solely on OFOs, or its ability to curtail customers to make up for the reduced capacity.

22. To prevent hourly deviations outside of an acceptable range, PG&E will implement a new storage service, Inventory Management, which requires at least 5 Bcf of inventory capacity, 300 MMcf/d of withdrawal capacity, 200 MMcf/d of injection capacity.

23. The acceptable inventory range is 3.9 to 4.3 Bcf.

24. PG&E's system is not designed for performing same day, hourly curtailments.

25. PG&E does not have a gas demand response program to allow customers to voluntarily curtail gas when supply is low.

26. To address significant, unplanned outages PG&E will implement a new service, Reserve Capacity, which requires at least 1 Bcf of inventory capacity, 250 MMcf/d of withdrawal capacity, and 25 MMcf/d of injection capacity.

27. The Reserve Capacity and Inventory Management services will be used to ensure the reliability of gas transmission service on its interconnected gas transmission system.

28. Implementation of PG&E's new storage strategy requires modifications to its tariffs.

29. Implementation of PG&E's new storage strategy requires PG&E to phase out its Standard Firm Service.

30. PG&E will reduce its Core Firm Service to 5,175 Mdth over a two-year period as it implements its new gas storage strategy.

31. Of the core service 1-day-in-10-year standard, PG&E will provide 318 MDth/d of withdrawal capacity from its storage fields. The remainder will be sourced from ISPs and Citygate.

32. PG&E's CGS department is responsible for executing gas storage contracts on behalf of the PG&E residential bundled customers who are not served by CTA.

33. ISPs are public utilities that are subject to the Commission's jurisdiction.

34. The Commission's credit requirements for ISPs provide that an independent third-party must evaluate the financial strength of the ISP and use that information to assess the adequacy of the ISP's insurance. In addition, the ISPs have liquidated damages clauses in their tariffs.

35. The storage fields owned by ISPs have a rate of return that is lower than PG&E's rate of return for equivalent services. In comparison to PG&E's storage fields, the ISPs' storage fields are generally more modern and require less wells to operate more storage capacity.

36. Using the reduced Core Firm Storage Capacity, the CGS group designed a gas supply portfolio for core customers. The portfolio requires additional intrastate capacity, ISP firm storage capacity, and the option to increase interstate pipeline capacity.

37. CTAs and PG&E's CGS group will compete to acquire storage resources from ISPs.

38. Currently, PG&E does not report on the amount of storage capacity held that the ISPs' storage fields.

39. PG&E will have visibility to the gas storage capacity that CTAs will acquire from ISPs on behalf of the CTA's core customers. However, CTA do not have visibility to the gas storage capacity the PG&E's CGS group will acquire from ISPs.

40. To provide reliable gas transmission service, PG&E determined that a portion of the core demand component of the reliability standard must be sourced from storage fields owned by either the ISPs or PG&E.

41. If PG&E eliminates the price commodity service, it could restructure its storage assets and requirements for other supply sources so that the present value of its revenue over 20 years would be $3.85 billion.

42. Joint ISPs do not currently summit S-MAP metrics to the Commission during audits conducted by the Safety and Enforcement Division.

43. SED's audits of the extent to which ISPs have implemented requirements set forth in their respective Safety Plans is currently limited to the PHMSA-related requirements.

**Facility Asset Family**

44. Because 65 percent of PG&E's compressor units are over 40 years old, PG&E plans to retire or replace obsolete compressor units, install security upgrades and ancillary equipment.

45. The majority of PG&E's forecasts are based on historical forecasts for each program over a 3- to 5-year period or contractor estimates.

46. PG&E plans to rebuild five Measurement and Control stations per year from 2019-2021.

47. Obtaining permits to perform the station rebuilds could delay PG&E's progress.

48. PG&E will start Phase I of its project to rebuild the Brentwood gas terminal during this rate case cycle.

49. The Measurement and Control Over-Pressure Protection program is new, so no historical cost data for this program is available to verify the credibility of PG&E's forecast.

50. An over-pressure event occurs when a pressure exclusion is 10 percent greater than PG&E's maximum allowable operating pipeline pressure.

51. The description of the scope of work for the capital expenditures for the Measurement and Control Over-Pressure Protection program in PG&E's testimony differs from the program description it asserts in data responses.

52. Costs for PG&E to comply with CARB rules are reflected in PG&E's expense forecast for the Measurement and Control program.

53. The memorandum account for the Critical Documents program was established pursuant to the 2015 GT&S rate case.

54. The PHMSA will issue a final rule for new regulations concerning gas station requirements.

55. PG&E's forecast for the Station Assessments program significantly exceeded its recorded costs in 2017.

56. The stations in the Compression and Processing and Measurement and Control programs are generally different, and PG&E's has not identified which stations will be upgraded during the 2019-2022 rate case period.

57. The lifespan of the Programmable Logic Circuits in compressor units is between 15-20 years old, the age of some of PG&E's circuits.

58. PG&E's evidence in support of its expense forecasts for the Compression and Processing Routine Capital and Expense program is less credible than TURN's record evidence.

59. PG&E's proposed capital forecast for the Measurement and Control Station Rebuilds program is just and reasonable if PG&E establishes a new one-way balancing account for this program.

**Transmission Pipeline Asset Family**

60. The highest number of In-Line upgrades that PG&E has performed is a given year is ten.

61. PG&E was scheduled to complete in-line upgrades for its highest risk (Tier 1) pipeline segments by the end of 2018.

62. The proposed In-Line reassessment work is not required to comply with 49 CFR Section 192.937(c) or any other regulation or Commission decision.

63. In D.16-06-056 PG&E was authorized to perform 505 miles of ECDA work but performed 324 miles.

64. In D.16-06-056 PG&E was authorized to perform 81 miles of internal corrosion direct assessments but performed 5 miles.

65. PG&E did not spend all of the funds authorized in D.16-06-056 for the ECDA program on ECDA work.

66. PG&E reprioritized to the TIMP program some but not of the funds that it was authorized in D.16-06-056 to spend on EDCA work.

67. PG&E does not explain how the remining funds authorized in D.16-06-056 for the EDCA work was used to provide public utility service.

68. PG&E has not shown that its decision to defer a portion of the EDCA work is consistent with the Deferred Work Settlement.

69. PG&E also diverted to the TIMP program funds authorized to perform pressure tests.

70. The pipelines that PG&E seeks to perform ECDA on are not statutorily required to be assessed until 2027.

71. The R-Squared value for the cost curve for longer pipeline segments is .098. PG&E used this cost curve, among others, to develop a forecast for its Hydrostatic Testing program.

72. Approximately 4,000 miles of pipeline on PG&E's transmission system are vulnerable to land movement threats.

73. D.16-06-056 did not authorize a specific unit cost for the Geo-hazard threat Identification and Mitigation program projects.

74. Approximately 32.2 miles of transmission pipeline located in HCAs do not meet the minimum depth of cover requirements.

75. At least 249 areas of PG&E's transmission pipeline segments traverse earthquake faults.

76. Approximately 103 idle gas gathering meters still need to be retired.

77. PG&E's capital and expense forecasts for the WRO program are outweighed by record evidence that is more credible than PG&E's supporting evidence.

78. PG&E's justification that it can perform 18 in-line upgrade projects per year is not credible.

79. PG&E's capital and expense forecasts for the Pipe Investigation and Field Engineering program are outweighed by record evidence that is more credible than PG&E's supporting evidence.

80. In D.16-06-056, the Commission rejected PG&E's request to change the TIMP balancing account from a one-way account to a two-way account. To address PG&E's concern that new legislation or rules could require it to spend more than the amount authorized for the TIMP program during the rate case period, the Commission allowed PG&E to establish a memorandum account for the TIMP program.

81. In the instant proceeding, PG&E raises the same concerns that new legislation will require it to spend more than the authorized amount for the TIMP program.

82. In the instant decision the Commission directed PG&E to continue using the TIMP memorandum account if, among other things, new legislation requires it to spend more than the authorized amount for the TIMP program.

83. PG&E's 2019 expense budget for the TIMP program is $270 million, which is $70 million larger than both the capital and expense budget authorized for this program in D.16-06-056.

84. For the pipe replacements that PG&E implemented in lieu of performing hydrostatic tests during 2015 to 2018, PG&E estimates that it has exceeded the

authorized unit costs established in D.16-06-056. PG&E provides adequate quantifiable support for cost overrun associated with the R-503 project.

**Corrosion Control**

85. Pursuant to 49 CFR Section 192, PG&E must identify and mitigate the impact that stray electric currents have on its gas transmission system.

86. PG&E will inspect five percent of its pipeline system to identify and repair segments that are at risk of atmospheric corrosion.

87. PG&E's justification for its expense forecast for the Atmospheric Corrosion program is outweighed by record evidence that is more credible than PG&E's supporting evidence.

88. The amount to cased-crossings that PG&E will need to replace during the rate case period should rise to 25.

89. Discharging one ampere from a pipeline could dissolve 21 points of metal per year. A BART train requires 800 amperes of DC. PG&E will install test stations at half mile intervals from the DC mass transit railways and stations.

90. PG&E will monitor the presence of corrosive liquids at 80 internal corrosion monitoring devices, six filters, 351 annual drips, 90 bi-monthly drips, and 70 other monitoring points during this rate case period.

91. PG&E will monitor the CP at 6,700 test stations and 2,800 cased crossings. PG&E will perform close interval surveys of 450 miles of transmission pipeline for each year of the rate case period.

92. PG&E will replace 10 groundbeds and 10 rectifiers for each year of the rate case period.

93. PG&E will replace or install 12 coupon test stations during the rate case period.

**Gas System Operations and Maintenance**

94. The SCADA system allows PG&E to monitor approximately 18,000 points on its transmission system and control approximately 1,940 points, including storage fields.

95. PG&E estimates that it will receive 13,242 locate and mark notification tickets during the rate case period.

96. PG&E will survey 12,500 miles of its transmission pipeline system to identify leaks during the rate case period.

97. PG&E will perform aerial patrols of its entire pipeline system at least 12 times per year.

98. To resolve the under-pressure issue on the Baja path, PG&E proposes to purchase gas supplies upstream of the Hinkley compressor station and then sell the purchased gas at Citygate.

99. The Commission's Energy Division uses PG&E's quarterly OFO reports to monitor PG&E's OFO activities.

100. A joint stipulation for the Technology and Security program capital expenditures is in Exhibit JS-02.

101. A joint stipulation for the Gas Transmission Storage and Support Environmental program forecast is in Exhibit JS-07.

102. As directed by D.16-06-056, PG&E submitted a reasonableness report for Line 407.

103. PG&E's capital forecast for the New Business program is outweighed by record evidence that is more credible than PG&E's supporting evidence.

104. PG&E's expense forecast for the Locate and Mark program is outweighed by record evidence that is more credible than PG&E's supporting evidence.

105. Pursuant to D.16-06-056, Ordering Paragraphs 57 and 58, all costs incurred for the Line 407 project over the 2015 rate case cycle should be included in the Line 407 Memorandum Account and are subject to a reasonableness review by the Commission.

106. PG&E's capital forecast for the Capacity Betterment program is outweighed by record evidence that is more credible than PG&E's supporting evidence.

107. With the exception for the estimated costs to comply with GHG rules, PG&E's expense forecast for the Station Maintenance program is outweighed by record evidence that is more credible than PG&E's supporting evidence.

108. PG&E's expense forecast for the Right-of-Way program includes $1.2 million for contingencies in the event that new legislation for vegetation management is proposed by state or local regulators.

**Results of Operations**

109. PG&E's forecasted 2017 capital expenditures is $838 million, and its recorded 2017 capital expenditures is $745 million.

110. PG&E's revised 2018 capital expenditures forecast is $965 million; its original forecast was $1.099 billion.

111. Decommissioning activities at the Los Medanos storage field will not begin on or before December 31, 2021.

112. PG&E will not produce all of the gas from the Los Medanos storage field by December 31, 2021.

113. The remaining useful life for the Los Medanos and Pleasant Creek storage fields is five years, until further notice from the Commission.

114. A joint stipulation for the depreciation expense parameters for all assets other than the Los Medanos and Pleasant Creek storage fields is in Exhibit JS-03.

115. PG&E's justification for its Local Transmission study is outweighed by record evidence demonstrating that the study is not credible to use as a basis for allocating its Local Transmission costs to ratepayers.

116. A joint stipulation for the SB 901 and Officer Compensation expenses is in Exhibit JS-08.

**Transmission and Storage Rate Design and Cost Allocation**

117. The backbone transmission rate design was adopted in D.16-06-056.

118. A stipulation on the backbone rate differential is in Exhibit JS-06.

119. The Local Transmission study is based on a hypothetical model of two separate transmission system, one for core customers and the other for noncore.

120. PG&E's transmission system is integrated and shared by both core and noncore customers.

121. The process for converting transactions in the balancing and memorandum accounts into rates is causing local transmission costs to be allocated to electric-generation-backbone customers.

**Other Ratemaking Issues**

122. A joint stipulation for the electric demand generation demand forecast for market responsive electric generators is in Exhibit JS-04.

123. The MarketBuilder program provides inaccurate forecasts for market responsive Electric Generation demand. The forecast is understated.

124. An upward adjustment of 54 MDth/d will resolve the MarketBuilder forecast discrepancies.

125. PG&E's local transmission rates are a part of the bid price for market-response Electric Generators.

126. All-electric homes and electric vehicles, among other devices, impact the demand for Electric Generation when the temperature is colder than normal.

**Other**

127. A joint stipulation for the post-test year mechanism is in Exhibit JS-05.

## Conclusions of Law

**General Issues**

1. Allowing PG&E to include another attrition year in its 2019 rate case cycle so that it can use the results of the its RAMP and the S-MAP proceedings in subsequent gas transmission and storage rate case applications is reasonable.

2. Requiring PG&E to use its RAMP process and the risk-analysis methodologies developed in the S-MAP proceeding in subsequent gas transmission and storage rate cases is reasonable.

3. Requiring PG&E to provide the new Annual GT&S Report on semi-annual basis is reasonable and should be adopted. The new report contains information the Commission currently receives on a quarterly and semi-annual basis.

**Natural Gas Storage Strategy**

4. PG&E's proposal to transition to a reliability-focused storage service strategy is reasonable given the gas market conditions and new federal and state regulations.

5. PG&E's proposal to use the Inventory Management service to resolve intraday and day-ahead inventory imbalances on its system is reasonable and should be adopted.

6. PG&E's proposal to use the Reserve Capacity service to resolve supply issues caused by equipment outages is reasonable and should be adopted.

7. PG&E's proposed inventory capacity levels for the Inventory Management and Reserve Capacity services are reasonable and should be adopted.

8. PG&E's proposal to reduce the level of Core Firm Services is consistent with its strategy to provide reliability-only storage services and, therefore, is reasonable and should be adopted.

9. PG&E's proposal to require its CGS department and the CTA to contract with Independent Storage Providers to obtain firm core storage services for core customers is reasonable and should be adopted.

10. Requiring PG&E's CGS department to use the contract evaluation and approval process set forth in Appendix I to contract with ISPs for core firm series is necessary to ensure that storage rates are just and reasonable.

11. Requiring PG&E to submit a report on an annual basis that states the amount of gas storage capacity currently held at an ISPs' storage facility and the amount of gas storage capacity that PG&E plans to hold at an ISPs' storage facility in the subsequent year is reasonable and should be adopted. To facilitate transparency, allowing the report to be available to CTAs is reasonable.

12. PG&E's proposal to build eleven new wells at the McDonald Island storage field is just and reasonable given the reduced storage capacities associated with it complying with state and federal regulations.

13. PG&E's capital forecast for the New Wells program is reasonable and should be adopted.

14. PG&E's proposal to sell or decommission the Pleasant Creek storage field is reasonable, provided that it submits a Tier 1 Advice Letter proposing a plan to obtain sales offers. The sale of the Pleasant Creek storage field is subject to PG&E filing a Section 851 application.

15. PG&E's proposal to sell or decommission the Los Medanos storage field is reasonable, but because it relies on assumptions about future capacity and supply conditions, approval of its proposal should be subject to a Tier 2 Advice

Letter that it must submit to demonstrate that it can provide reliable gas storage and transmission service without the storage field. PG&E must also submit a Tier 1 Advice Letter proposing a plan to obtains ales offers.

16. In light of the record, PG&E has not demonstrated that its Below-Ground Storage Decommissioning expense forecast is just and reasonable.

17. PG&E's Above-Ground Decommissioning expense forecast is reasonable and should be adopted.

18. PG&E's justification for why it believes that it will not be able to sell the Los Medanos and Pleasant Creek storage fields is unsupported.

19. PG&E's proposal to supply its reliability standard using the components in Section III of the Memorandum of Understanding is reasonable and should be adopted.

20. PG&E's proposals to modify Tariff G-CFS concerning changes for CTA and to its Core Firm Service are reasonable and should be adopted.

21. PG&E's proposal to require the Commission's Energy Division to monitor the minimum inventory that each CTA must store is unsupported. Having the Energy Division oversee PG&E's monitoring of the CTAs is a reasonable approach.

22. PG&E's proposal for allocating storage capacity for its storage services is reasonable and should be adopted.

23. PG&E's proposal for allocating storage costs for Core Service, Inventory Management, and Reserve Capacity is reasonable and should be adopted.

24. The ISP responsibilities set forth in section IV of the Memorandum of Understanding is reasonable, provided that the ISPs submit an advice letter regarding their coordination with PG&E to resolve imbalance issues.

25. The general provisions set forth in section VII of the MOU are reasonable, provided that we clarify that if the MOU is amended or changed, the revised MOU will not be effective until the revision is approved by the Commission.

26. Requiring Joint ISPs to submit S-MAP metrics so that the Commission can evaluate the safety of the Joint ISPs' storage operations is reasonable and should be adopted.

27. Requiring PG&E to propose a Gas Demand Response program by January 30, 2020, is reasonable because providing a mechanism for customers to voluntarily curtail load will give PG&E more options to operate its system while reducing unwanted service disruptions.

28. Requiring SED to analyze GSRB's audit process to identify instances where the GSRB's annual safety audit does not verify that the ISPs have complied with a requirement in the ISPs' Safety Plans is reasonable and should be adopted.

**Core Gas Supply**

29. PG&E's proposal to provide revised storage capacity parameters for core is justified by supporting evidence.

30. PG&E's request to revise D.15-10-050 to adjust its pipeline capacity consistent with the revised storage capacity parameters is reasonable and should be adopted.

31. PG&E's request to require CTA to use the Independent Storage Provider contract approval process set forth in D.06-07-010 is unnecessary and, therefore, should be denied.

32. PG&E's request to be exempt from the ISP contract approval process set forth in D.06-07-010 should be granted in part. The instant decision sets forth a revised contract approval process in Appendix I.

33. PG&E's proposal to revise the credit requirements for ISPs lacks the requisite credibility and, therefore, should be denied.

34. PG&E's request to revise the CPIM authorized in Ordering Paragraph 32 of D.16-06-056 should be granted, provided that PG&E files an advice letter with the revisions.

**Storage Asset Family**

35. The adjusted forecasts for PG&E's Reworks and Retrofit program are reasonable and should be adopted.

36. Requiring PG&E to use the seven-year forecast in its testimony is reasonable as parties had notice and the opportunity to respond to the forecast.

37. PG&E's proposed forecast for the Controls and Continuous Monitoring Program is reasonable and should be adopted.

38. PG&E's proposed forecast for the Repair and Maintenance Program is reasonable and should be adopted.

39. PG&E's proposed forecast for the Other Well-Related Projects Program is reasonable and should be adopted.

40. The adjusted forecast for the Integrity Inspection and Surveys Program is reasonable and should be adopted.

**Facilities Asset Family**

41. After removing Physical Security program costs of $4.95 million, PG&E's forecast for the Compression and Processing Replacements Program is reasonable and should be granted.

42. PG&E's proposed capital forecast for the Compression and Processing Routine Capital and Expense program is reasonable and should be adopted.

43. The adjusted expense forecast for PG&E's Compression and Processing Routine Capital and Expense program is reasonable and should be adopted.

44. PG&E's proposed capital forecast for the Measurement and Control Terminal Upgrades program is reasonable and should be adopted.

45. PG&E's capital forecasts for the Measurement and Control Over-Pressure Protection program lack credibility and, therefore, are denied. PG&E should track the cost incurred for this program in a memorandum account.

46. PG&E's proposed forecasts for the Measurement and Control Quality Assessment program are reasonable and should be adopted.

47. PG&E's proposed forecasts for the Measurement and Control Routine Capital and Expense program are reasonable and should be adopted.

48. PG&E's request to adopt its proposed expense forecast for the Critical Documents Program unreasonable and should be denied.

49. PG&E's proposed expense and capital forecasts for the Station Assessments program are reasonable if PG&E establishes a new one-way balancing account as discussed in section 7.9 of the instant decision.

50. PG&E's proposed capital forecast for the Compression and Processing Compressor Unit Control Replacements program is reasonable and should be adopted.

51. PG&E's proposed capital forecast for the Compression and Processing Compressor Upgrade Station Control program is reasonable and should be adopted.

52. PG&E's proposed capital forecast for the Compression and Processing Emergency Shutdown System program is reasonable and should be adopted.

53. PG&E's proposed capital forecast for the Compression and Processing Gas Transmission Upgrades program is reasonable and should be adopted.

54. PG&E's proposed capital forecast for the Becker System Upgrades program is reasonable and should be adopted.

55. PG&E's proposed expense forecast for the Compression and Processing Compressor Upgrade Station Control program is reasonable and should be adopted.

56. The adjusted capital and expense forecasts for Pacific Gas and Electric Company's (PG&E) In-line Inspection program are reasonable and should be adopted.

55. The record demonstrates it is reasonable to forecast that PG&E will perform 12 in-line upgrade projects per year.

56. Because the in-line upgrade scope of work is reduced to 12 in-line upgrades per year, it is reasonable to reduce the related in-line inspection and mitigation work for the In-Line Inspection program.

57. The adjusted expense forecasts for PG&E's ECDA program is reasonable and should be adopted.

58. Of the 181 miles of deferred work for the ECDA program, the record demonstrates that a portion of the authorized funds for the deferred work was appropriately reprioritized; thus, allowing PG&E to defer 25 percent of the of the EDCA work is reasonable. PG&E has not shown that its decision to defer the remaining 75 of the EDCA work authorized for 2015 rate case cycle is consistent with the Deferred Work Settlement.

59. PG&E's expense forecast ICDA is unreasonable and should not be adopted. PG&E should be permitted to recover reasonable expenditures for this program.

60. PG&E's proposed expense forecast for the Transmission Integrity Management Program Pressure Test program is just and reasonable and should be adopted.

61. The adjusted expense forecast for PG&E's Pipe Replacement in Lieu of Hydrostatic program is just and reasonable and should be adopted because it removes nonrecurring high-cost and low-cost outliers from PG&E's forecast.

62. PG&E's proposed capital forecast for the Pipe Replacement in Lieu of Hydrostatic program is just and reasonable and should be adopted.

63. With the exception of the cost overrun for project R-503, PG&E does not provide adequate justification for exceeding the authorized unit costs for performing pipe replacements in lieu of hydrostatic tests from 2015-2018.

64. PG&E's proposed capital forecast for the Hydrostatic Testing program for D.11-06-017/NTSB projects is just and reasonable and should be adopted.

65. PG&E's proposed expense forecast for the Hydrostatic Testing program for D.11-06-017/NTSB projects is reasonable if it establishes a new one-way balancing account for this program.

66. PG&E's proposed capital and expense forecasts for the Pipe Replacement program are just and reasonable and should be adopted.

67. PG&E's proposed capital and expense forecasts for the Geo-Hazard Threat Identification and Mitigation program are just and reasonable and should be adopted.

68. PG&E's proposed expense forecasts for the Risk Analysis program, a subprogram of the Identification and Mitigation Support program, is just and reasonable and should be adopted.

69. The adjusted expense forecast for PG&E's Root Cause Analysis program, a subprogram of the Identification and Mitigation Support program, is reasonable and should be adopted.

70. PG&E's proposed expense forecast for the Root Cause Analysis program does not consider that, because the historical costs for this program have

declined for the last three years, the last recorded year should be used; thus, because its forecast does not include 2017 recorded costs, its forecast is unreasonable and should not be adopted.

71. PG&E's capital forecasts for PG&E's Valve Automation and Valve Safety and Reliability programs, which are subprograms of the Emergency Response program, are just and reasonable and should be adopted.

72. PG&E's expense forecast for the Valve Safety and Reliability program is reasonable and should be adopted.

73. The adjusted expense forecast for PG&E's Public Awareness Program, a subprogram of the Emergency Response program, is reasonable and should be adopted.

74. PG&E's proposed expense forecast for the Public Awareness Program does not consider that, because the historical costs for this program have declined for the last three years, the last recorded year should be used; thus, because its forecast does not include 2017 recorded costs, its forecast is unreasonable and should not be adopted.

75. PG&E's expense forecast for the Class Location program is just and reasonable and should be adopted.

76. PG&E's capital forecast for the Class Location – Replacements program is just and reasonable and should be adopted.

77. PG&E's proposed expense forecast for the Class Location—Hydrotest program includes historical project costs that are outliers; thus, its forecast is unreasonable and should not be adopted.

78. The adjusted expense forecast for PG&E's Class Location – Hydrotest program is just reasonable and should be adopted.

79. PG&E's capital and expense forecast for the Shallow and Exposed Pipe program is just and reasonable and should be adopted.

80. The adjusted capital and expense forecasts for PG&E's WRO program is just reasonable and should be adopted.

81. The adjusted capital and expense forecasts for PG&E's Pipe Investigation and Field Engineering program is just reasonable and should be adopted.

82. PG&E's capital and expense forecast for the Earthquake Fault Crossings and Gas Gathering programs are just and reasonable and should be adopted.

**Corrosion Control**

83. PG&E's expense forecast for the AC Interference program is just and reasonable and should be adopted.

84. PG&E's proposed capital forecast for the AC Interference program is just reasonable, provided that it establishes a new one-way balancing account for this program.

85. PG&E's capital forecast for the Atmospheric Corrosion program is just and reasonable and should be adopted.

86. The adjusted expense for PG&E's Atmospheric Corrosion program is just and reasonable and should be adopted, provided that PG&E establishes a one-way balancing account for this program.

87. PG&E's capital and expense forecast for the Casings program are just and reasonable and should be adopted.

88. PG&E's capital and expense forecast for the DC Interference program are just and reasonable and should be adopted.

89. PG&E's capital and expense forecast for the Internal Corrosion program are just and reasonable and should be adopted, provided that PG&E establishes a one-way balancing account for the capital expenditures.

90. PG&E's expense forecasts for the Routine Corrosion program are just and reasonable and should be adopted.

91. PG&E's expense forecasts for the Close Interval Survey, Corrosion Support, and Test Station programs are just and reasonable and should be adopted.

92. PG&E's expense forecasts for the CP and StanPac programs are just and reasonable and should be adopted.

**Gas System Operations and Maintenance**

93. PG&E's revised capital forecast for the Capacity for Load Growth, a subprogram of the Capacity Projects program, is just and reasonable and should be adopted.

94. The adjusted capital forecast for the Capacity Betterment program is just and reasonable and should be adopted.

95. PG&E's capital forecast for the Capacity for Normal Operating Pressure Reductions is for disallowed deferred work and, therefore, unjust and unreasonable. PG&E should still perform the forecasted scope of work for this program.

96. The adjusted capital forecast for the New Business program, a subprogram of the Customer-Connected Equipment program, is just and reasonable and should be adopted.

97. PG&E's capital forecast for the Meter Sets-Power Plant program, a subprogram of the Customer-Connected Equipment program, is just and reasonable and should be adopted.

98. PG&E's proposal to convert its 25 percent share ownership in the Gill Ranch Storage into a utility asset because this asset will be used to support the Reliability Standard is reasonable and should be adopted.

99. PG&E's capital and expense forecasts for the Gill Ranch Storage program are just and reasonable and should be adopted.

100. PG&E's expense forecasts for the Gas Transmission Supervisory Control and Data Acquisition Visibility program are just and reasonable and should be adopted.

101. PG&E's expense forecast for the Operations program is just and reasonable and should be adopted.

102. The adjusted expense forecast for the Locate and Mark program is just and reasonable and should be adopted.

103. The adjusted expense forecast for the Station Maintenance program is just and reasonable and should be adopted.

104. The adjusted expense forecasts for the Right-of-Way program is just and reasonable and should be adopted.

105. PG&E's expense forecasts for the Leak Management, Pipeline Patrol, and Pipeline Maintenance programs are just and reasonable and should be adopted.

106. PG&E's proposal for the Limited Trading Authority program is just and reasonable, provided the PG&E files an annual report on the status of the trading transactions and a Tier 2 Advice Letter if it determines that a Request for Offer process should be implemented.

107. PG&E's request to recover $180.8 million for the Line 407 is just and reasonable and should be adopted.

108. PG&E's request to submit a Tier 2 Advice Letter to manage the over-collections or additional costs to construct Line 407 should be denied.

109. Requiring PG&E to track the remaining project expenditures, forecasted to be $11 million, Line 407 in the Line 407 Memorandum Account is reasonable.

110. Permitting PG&E to track expenditures related to new vegetation rules and regulations in the memorandum account that this decision directs it to establish in Order Paragraph 56 is reasonable.

**Results of Operations**

111. PG&E's methodology for calculating A&G expenses is reasonable and should be adopted.

112. Requiring PG&E to use the recorded rate base for 2017 and remove deferred work for the Direct Assessment program is reasonable; the adjusted rate base for PG&E's property, plant and equipment, should be adopted.

113. Requiring PG&E to use a five-year remaining useful life for Los Medanos and Pleasant Creek storage fields is reasonable.

114. Requiring PG&E to use a five-year amortization period to recover decommissioning expense for Los Medanos and Pleasant Creek storage fields is reasonable.

115. PG&E's calculations for taxes in Exhibit PG&E-2, Tables 15B-2, 15-B-3, and 15B-4 are reasonable and should be adopted.

116. PG&E's Backbone rate design methodology is reasonable and should be adopted.

117. PG&E's existing methodology for allocating Local Transmission cost, using cold-year coincident-peak demand, is just and reasonable and should be adopted.

118. PG&E's Storage rate design and cost allocation are reasonable and should be adopted.

119. Requiring PG&E to adjust its rate base using actual capital additions for 2017 and 2018 is reasonable and should be adopted.

**Other Ratemaking Issues**

120. Requiring PG&E to increase its forecast demand for Market Responsive Electric Generation by an annual daily average of 54 MDth/d and to apportion the increase to local transmission and backbone throughput based on 2017 throughput is reasonable.

121. PG&E's forecast for Off-System Transmission Revenues is reasonable and should be adopted.

122. PG&E's proposed rate for the CAC is reasonable and should be adopted.

123. PG&E's Electric Generation rate design is reasonable and should be adopted.

124. Requiring PG&E to participate in workshops to evaluate proposals to revise the Electric Generation Local Transmission rate design is reasonable. Inviting CAISO's Department of Market Monitoring to participate in the workshop(s) and evaluate proposals to revise PG&E's Electric Generation local transmission rate design is reasonable.

125. If PG&E does not decommission the Los Medanos storage filed, requiring PG&E to file a Tier 1 Advice Letter proposing a method for refunding ratepayers for the associated decommissioning expense and the depreciation costs beyond the amount that PG&E would have recovered using the useful life authorized in the 2015 Gas Transmission and Storage rate case is reasonable.

126. Requiring PG&E to continue to submit quarterly Operational Flow Order reports is reasonable because the Commission's Energy Division uses them to monitor PG&E's OFO process.

127. Requiring PG&E to include in its next GT&S rate case application the cold-year forecast for Electric Generation gas demand is reasonable and should be adopted.

**Stipulations**

128. The following joint stipulations are reasonable and should be adopted: JS-01, Gas Transmission and Storage Reports, as adjusted; JS-02, Gas Operations Technology and Security; JS-03, Depreciation (non-NGSS); JS-04, Throughput Forecast; JS-05, Post-Test Year Ratemaking; JS-06, Backbone Path Rate Differential; JS-07, Other Gas Transmission Storage and Support, Environmental; JS-08, Senate Bill 901 and Officer Compensation.

## O R D E R

**IT IS ORDERED** that:

1. Pacific Gas and Electric Company is authorized to collect, through rates and authorized rate making accounting mechanisms, the adopted revenue requirements set forth in Appendix C and E of this decision for the rate case period.

2. An additional attrition year is added to Pacific Gas and Electric Company's gas transmission and storage application 17-11-009 to run from January 1, 2019 through December 31, 2022. The scope of work for the third attrition year shall be similar to the work performed in 2021 and all disallowances adopted for 2019-2021 apply to the third attrition year.

3. The rates stated in Appendix H are adopted. Pacific Gas and Electric Company shall file a Tier 1 Advice Letter with a requested effective date of October 1, 2019, to implement the adopted rates, subject to Energy Division approval.

4. Pacific Gas and Electric Company shall file its gas transmission and storage application, covering 2023-2025, in 2021, unless otherwise directed by the Commission in Rulemaking 13-11-006.

5. The under-collection in the Gas Transmission and Storage Memorandum Account shall be amortized over 15 months, starting on October 1, 2019.

6. Pacific Gas and Electric Company's (PG&E) risk management approach is adopted for use in this gas transmission and storage application. For the next rate case cycle (2023-2025), PG&E must integrate into its risk management process the Risk Assessment Mitigation Phase and use the Safety Model Assessment Proceeding process to identify and evaluate PG&E's proposed work pace and forecast for its gas transmission and storage programs.

7. Pacific Gas and Electric Company's proposal to implement new demand components for its System Supply Reliability Standard is adopted. The demand components are set forth in Table 1, section 5.3, of the instant decision.

8. Pacific Gas and Electric Company's proposal to implement the Inventory Management service, which requires 300 MMcf/d of withdrawal capacity, 200 MMcf/d of injection capacity, and 5 Bcf of Inventory capacity, is adopted.

9. Pacific Gas and Electric Company's proposal to implement the Reserve Capacity, which requires 250 MMcf/d of withdrawal capacity, 25 MMcf/d of injection capacity, and 1 Bcf of Inventory capacity, is adopted.

10. Pacific Gas and Electric Company's (PG&E) next rate case application must include a proposal to improve its curtailment process. The proposal shall include an evaluation of whether PG&E can implement hourly curtailments.

11. On or before January 30, 2020, Pacific Gas and Electric Company must file an application with a proposal to implement a Gas Demand Response program as discussed in section 5 of this decision.

12. Pacific Gas and Electric Company's proposal to support its Reliability Standard by using the storage and pipeline capacity set forth in Section III of the

Memorandum of Understanding and section 5.9.3, Table 4, of the instant decision is granted.

13. The storage capacity allocations for storage services set forth in Section V of the Memorandum of Understanding and section 5.9.5, Tables 5 and 6, of the instant decision are granted.

14. The cost allocation percentages for storage services set forth in Section V of the Memorandum of Understanding and section 5.9.5, Table 7, of the instant decision are adopted. Requests to opt-out of cost allocation for the Inventory Management and Reserve Capacity storage services are denied.

15. Pacific Gas and Electric Company's (PG&E) proposal to eliminate its Gas Schedule G-SFS from its tariff after the seven-year step-down period is adopted.

16. Pacific Gas and Electric Company shall submit a Tier 2 Advice letter, within 30 days of the date that this decision is final, to establish a tracking account to record cushion gas transactions as directed in section 5.8.5.4 of this decision.

17. Pacific Gas and Electric Company (PG&E) shall credit ratepayers for the cushion gas that is sold from its Los Medanos and Pleasant Creek storage fields consistent with discussion in section 5.8.5.4 of this decision. The disposition of the amounts recorded to the tracking account will be considered in PG&E's next gas transmission and storage rate case.

18. Pacific Gas and Electric Company's proposal to reduce the storage capacity for its Core Firm Service to 25 MDth/d for maximum injection capacity, 318 MDth/d for maximum withdrawal capacity from December to February, and 159 MDth/d for November and March is adopted.

19. The core customer demand component of the Reliability Standard is 2,580 thousand decatherms per day (MDth/d). Pacific Gas and Electric

Company's proposal to supply gas to meet the core customer demand component by using 318 MDth/d of withdrawal capacity from its storage fields, 1,255 MDth/d from interstate pipeline capacity, with the remaining MDTH/d sourced by Citygate and Independent Storage Providers (ISP) is adopted, subject to the ISP contract requirements set forth in Appendix I. In addition, to serving core customers, ISPs must provide standby service.

20. Pacific Gas and Electric Company's proposal to revise Decision 15-10-050 to (1) increase the winter range maximum percentage of average annual demand from 100 percent to 162 percent, (2) reduce the March range minimum to 80 percent of the average annual daily demand, and (3) submit a Tier 1 advice letter to seek an exception to the capacity planning range if the anticipated shortfall is more than 50 thousand decatherms per day during a given month is adopted.

21. Pacific Gas and Electric Company's (PG&E) proposal to require Core Transport Agents to contract with either PG&E or an Independent Storage Provider to procure enough gas to meet the Reliability Standard is adopted.

22. Pacific Gas and Electric Company's proposal to use the guidelines set forth in Advice Letter 3884-G to demonstrate that Core Transport Agents have procured the requisite capacities of firm storage to meet the Reliability Standard is adopted.

23. Pacific Gas and Electric Company's proposal to modify Tariff G-CFS to (1) provide that PG&E will share with Core Transport Agents, California Public Advocates Office, and The Utility Reform Network the total core storage requirement, and (2) establish residual core storage service is granted. Within 30 days of the date that this decision is final, PG&E shall submit a Tier 2 Advice Letter with the proposed changes to Tariff G-CFS.

24. Pacific Gas and Electric Company's (PG&E) proposal to require the Energy Division to monitor the Core Transport Agents' (CTA) compliance with PG&E's minimum storage inventory is denied. The Energy Division will oversee PG&E's monitoring of the CTAs' compliance. To facilitate that process, PG&E must file a Tier 2 Advice Letter, within 30 days of the issue date of this decision, with its proposal to monitor the amount of gas storage inventory CTAs procure and the level to gas that the CTAs must hold in storage to support the Reliability Standard. PG&E must also identify the gas storage information that CTAs should provide to facilitate the monitoring process and a fee or other mechanism to incentivize CTAs to comply with the gas storage requirement.

25. Pacific Gas and Electric Company must submit a quarterly report to the Energy Division that lists the Core Transport Agents that are not complying with the core gas storage requirements.

26. Pacific Gas and Electric Company's proposal to modify Tariff G-CFS to revise the Core Firm Service capacities is adopted as is its proposal to determine the effective date of the adopted modifications Tariff G-CFS. Within 30 days of the date that this decision is final, PG&E shall submit a Tier 2 Advice Letter with the proposed changes to Tariff G-CFS.

27. The responsibilities for Independent Storage Providers (ISP) set forth in Section IV of the Memorandum of Understanding are granted, provided that Central Valley Gas Storage, LLC, Lodi Gas Storage, LLC, Wild Goose Storage, LLC, Gill Ranch, LLC, and Pacific Gas and Electric Company (PG&E) jointly submit annual reports to the Commission's Energy Division with information that identifies instances where PG&E requested assistance from an ISP to resolve inventory imbalance issues, describes why the ISP's assistance was needed, and explains whether that ISP provided assistance and if not, why not.

28. Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to inform the Energy Division on the status of the storage withdrawal capacity of its storage fields. The report shall be submitted during the third week of December each year until further notice, starting in December 2019.

29. Central Valley Gas Storage, LLC, Lodi Gas Storage, LLC, Wild Goose Storage, LLC, and Gill Ranch, LLC, (ISPs) shall submit an annual report informing the Energy Division of the impact that complying with the DOGGR May 19 Rule is having on the ISPs' gas storage facilities, including withdrawal and injection capacity. The report shall be submitted during the third week of December each year until further notice, starting in December 2019.

30. On an annual basis, Central Valley Gas Storage, LLC, Lodi Gas Storage, LLC, Wild Goose Storage, LLC, and Gill Ranch, LLC, shall submit to the Commission's Safety and Enforcement Division and Energy Division the Safety Model Assessment Proceeding metrics related to their storage operations, starting on January 30, 2020.

31. On an annual basis, starting on December 31, 2019, PG&E shall submit to the Commission's Energy Division and Core Transport Agents a report specifying the amount of gas storage capacity (e.g., injection, withdrawal, inventory) that it is holding at Central Valley Gas Storage, LLC, Lodi Gas Storage, LLC, Wild Goose Storage, LLC, and Gill Ranch, LLC, and any other storage provider consistent with the requirements set forth in Appendix I.

32. Pacific Gas and Electric Company shall submit a Tier 2 Advice Letter, within 30 days of the date that this decision is final, to implement the report changes discussed in Section 3.2 of the instant decision.

33. Pacific Gas and Electric Company shall submit a Tier 1 Advice Letter, within 60 days of the date that this decision is final, to propose a process for

transition to its Risk Assessment Mitigation Phase process as discussed in Section 4.3 of the instant decision.

34. Pacific Gas and Electric Company's proposal to require Independent Storage Providers to comply with credit requirements that are different from requirements set forth by the Commission is denied.

35. Section VII, General Provisions, of the Memorandum of Understanding (MOU) are adopted in part. If the MOU is amended or changed, the revised MOU will not be effective until it is approved by the Commission. Pacific Gas and Electric Company must use a Tier 2 Advice Letter to file changes to the MOU.

36. Pacific Gas and Electric Company's request to implement conforming changes to the Core Procurement Mechanism as described herein, is granted.

37. Pacific Gas and Electric Company's proposal to require Core Transport Agents to use the Independent Storage Provider contact approval process set forth in Ordering Paragraph 4(a) of Decision 06-07-010 is denied.

38. Pacific Gas and Electric Company's (PG&E) request to exempt its Core Gas Supply (CGS) group from the Independent Storage Provider (ISP) contact approval process set forth in Ordering Paragraph 4(a) of Decision 06-07-010 is granted in part. PG&E's CGS group must use the revised process set forth in Appendix I to execute CGS contracts with ISPs.

39. Pacific Gas and Electric Company's proposal to satisfy a portion of the Reliability Standard by sourcing 857 million cubic feet per day of gas storage withdrawal capacity from its storage fields, including its share in Gill Ranch, is adopted.

40. Pacific Gas and Electric Company's proposal to build eleven new wells at its McDonald Island storage field at capital costs of $25 million in 2019 and $31 million in 2020 is adopted.

41. Pacific Gas and Electric Company's proposal to convert its 25 percent ownership share in the Gill Ranch storage field into a utility asset is granted.

42. Pacific Gas and Electric Company's (PG&E) proposal to sell or decommission the Pleasant Creek storage field is adopted, subject to PG&E demonstrating that it has attempted to sell the storage field. On or before January 31, 2020, PG&E must submit a Tier 1 Advice Letter proposing a plan to receive offers from potential purchasers.

43. Pacific Gas and Electric Company's (PG&E) proposal to sell or decommission the Los Medanos Storage field is granted in part, subject to further action to sell the storage fields and Commission approval. PG&E must file a Tier 2 Advice Letter on December 31, 2021 or later demonstrating that PG&E has the requisite storage capacity to operate without the storage field. In the Tier 2 Advice Letter, PG&E must provide metrics to demonstrate that its storage withdrawal capacity losses do not exceed the amount that it asserts in its testimony, 40 percent. In addition, PG&E must include an analysis of supply constraints, particularly for out-of-state gas supply.

44. Pacific Gas and Electric Company's (PG&E) forecast for below-ground storage well decommissioning costs is not adopted. If PG&E is not able to identify quotes to decommission its storage wells for less than $1.2 million per well, PG&E must file a Tier 2 Advice letter on or after December 31, 2021, to obtain approval to include an amount of $1.2 million or above per well in rates.

45. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way

balancing account for cost incurred for below-ground storage well decommissioning activities.

46. Pacific Gas and Electric Company's forecast for above-ground storage well decommissioning costs is adopted, subject to the disposition of the Tier 1 Advice Letter directed in Order Paragraph 34.

47. Pacific Gas and Electric Company (PG&E) must remove Physical Security program costs of $4.95 million from the Compression and Processing Replacements Program. If that amount exceeds the amount that Decision 16-06-056 authorized PG&E to spend, PG&E must demonstrate that the cost overrun is reasonable in the next Gas Transmission and Storage rate case proceeding.

48. Pacific Gas and Electric Company's (PG&E) proposal to convert the storage wells at Los Medanos and Pleasant Creek storage fields into production wells starting in November 1, 2019, is granted in part. PG&E must maintain at least half of the gas capacity in the wells at the Los Medanos storage field until the Energy Division responds to PG&E's Tier 2 Advice Letter concerning the decommissioning of the storage field.

49. If Pacific Gas and Electric Company (PG&E) does not decommission the Los Medanos storage field, PG&E must to must file a Tier 2 Advice Letter, within 60 days of the Energy Division's response to PG&E's Tier 2 Advice Letter required in Ordering Paragraph 35, proposing a methodology to remove the decommissioning costs from rates, update the depreciation parameters for Los Medanos, and refund ratepayers for the associated excess decommissioning and depreciation expense that PG&E recovered.

50. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way

balancing account for cost incurred for the Measurement and Control Station Rebuilds program.

51. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a two-way Gas Storage Balancing Account.

52. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way balancing account for expenses incurred for the Hydrostatic Testing Program.

53. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way balancing account for expenses incurred for the Atmospheric Corrosion program.

54. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way balancing account for capital expenditures incurred for the Internal Corrosion program.

55. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way balancing account for capital expenditures incurred for the Physical Security program.

56. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way balancing account for capital-related costs incurred for the AC Interference program.

57. Pacific Gas and Electric Company (PG&E) must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a

one-way balancing account for In-Line Upgrade Program. PG&E shall record the capital expenditures for the In-Line Upgrade Program in this balancing account instead of the Transmission Integrity Management Program one-way balancing account.

58. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a one-way balancing account for capital-related costs incurred for Casing program.

59. Pacific Gas and Electric Company (PG&E) must track the sales of cushion gas from the Los Medanos and Pleasant Creek storage fields and the corresponding credit to ratepayers. PG&E shall submit a report of these transactions on an annual basis starting on January 30, 2020, until all of the cushion gas from the Los Medanos and Pleasant Creek storage fields has been removed.

60. Pacific Gas and Electric Company's request to discontinue the Engineering Critical Assessments Program Balancing Account is denied.

61. Pacific Gas and Electric Company's request to discontinue the Work Required by Others Balancing Account is granted.

62. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for capital expenditures for the Measurement and Control Over-Pressure Protection program. The account is subject to a reasonableness review by the Commission during the next rate case.

63. Pacific Gas and Electric Company (PG&E) must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for the In-Line Inspection Program to account for the cost it incurs to upgrade more than 12 in-line upgrade projects per year for the entire

rate case period. PG&E must include costs associated with performing additional testing and other related work. PG&E may use this memorandum account to track the costs of In-Line reassessment work discussed in section 8.1 of this decision. The account is subject to a reasonableness review by the Commission during the next rate case.

64. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for the Internal Corrosion Direct Assessments program. The account is subject to a reasonableness review by the Commission during the next rate case.

65. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for expenses for the Compression and Processing Routine Capital and Expense program. The account is subject to a reasonableness review by the Commission during the next rate case.

66. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for expenses for the Risk Cause Analysis program, a subprogram of the Identification and Mitigation Support program discussed in section 8.4 of the instant decision. The account is subject to a reasonableness review by the Commission during the next rate case.

67. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for tracking and recording incremental costs to comply with new federal or state statutes, regulations and rules that are issued in

between rate case cycles and that are not already addressed and recorded in another account.

68. Pacific Gas and Electric Company must submit a Tier 2 Advice Letter, within 30 days of the issue date of the instant decision, to establish a memorandum account for Locate and Mark program. The account is subject to a reasonableness review by the Commission during the next rate case.

69. Pacific Gas and Electric Company's request to discontinue the Hydrostatic Pipeline Testing Memorandum Account is granted.

70. Pacific Gas and Electric Company's request to discontinue the Transmission Integrity Management Program Memorandum Account is denied.

71. Pacific Gas and Electric Company's request to discontinue the Hydrostatic Station Testing Memorandum Account is granted.

72. Pacific Gas and Electric Company's request to discontinue the Critical Documents Program Memorandum Account is denied.

73. Pacific Gas and Electric Company's request to discontinue memorandum account for the Station Assessment Programs (e.g., Engineering Critical Assessment Phase I) is denied.

74. Pacific Gas and Electric Company must continue to track costs for new transmission integrity management statutes or rules effective after January 1, 2015 in the Transmission Integrity Management Program memorandum account.

75. Pacific Gas and Electric Company's request to discontinue the Tax Normalization Memorandum Account is granted.

76. Pacific Gas and Electric Company's request to discontinue the Gas Transmission Storage Memorandum Account is denied.

77. Pacific Gas and Electric Company's request to discontinue the Line 407 Memorandum Account is denied.

78. Pacific Gas and Electric Company must submit a Tier 1 Advice Letter, within 60 days of the issue date of the instant decision, to provide the status of retiring its remaining gas gathering assets.

79. Within 90 days of the date of this decision, the Energy Division must convene a workshop to evaluate the proposals to change the Electric Generation Local Transmission rate design. Pacific Gas and Electric Company must participate in the first workshop and any subsequent workshops.

80. Pacific Gas and Electric Company must file a Tier 3 Advice letter if a proposal to modify its Electric Generation Local Transmission rate has been identified (1) through the workshop ordered in Ordering Paragraph 67(2) using the parameters discussed in 14.4.3, and (2) in consultation with the California Independent System Operator (CAISO). The advice letter must be submitted within 30 days of meeting the aforementioned three conditions.

81. Pacific Gas and Electric Company (PG&E) must submit a Tier 1 Advice Letter with proposed revisions to the Core Procurement Incentive Mechanism authorized in Ordering Paragraph 32 of D.16-06-056. The advice letter must be submitted 30 days after PG&E receives feedback from the Commission's Public Advocates Office.

82. Within 60 days of the date of that this decision is final, Pacific Gas and Electric Company (PG&E) must file a Tier 2 Advice letter with a proposal to revise its process for converting its balancing and memorandum accounts into rates so that the process allocates costs in manner that is consistent with this decision. PG&E may use the process suggested in section 14.4 of this decision or devise its own revisions to the existing process.

83. The following joint stipulations are adopted: JS-01, Gas Transmission and Storage Reports, as adjusted by the decision; JS-02, Gas Operations Technology

and Security; JS-03, Depreciation (non-Natural Gas Storage Strategy); JS-04, Throughput Forecast; JS-05, Post-Test Year Ratemaking; JS-06, Backbone Path Rate Differential; JS-07, Other Gas Transmission Storage and Support, Environmental; JS-08, Senate Bill 901 and Officer Compensation.

84. As required in Decision 12-12-030, Pacific Gas and Electric Company shall include an update regarding the use of automated shut-off valves, particular in seismic zones, in its next Gas Transmission & Storage rate case.

85. Pacific Gas and Electric Company shall increase the demand forecast for market responsive electric generation by 54 MDth/d and apportion the increase to local transmission and backbone throughput based on 2017 throuput.

86. Pacific Gas and Electric Company shall provide a separate cold-year forecast of Electric Generation gas demand in its next Gas Storage and Transmission rate case application.

87. Pacific Gas and Electric Company (PG&E) shall submit a Tier 2 Advice Letter with 30 days of the date that this decision is final to establish a memorandum account to track and record the difference in revenue requirement resulting from the difference between the year-end 2018 rate base balance (which includes PG&E's forecasted $965 million of rate base additions) and the actual year-end 2018 rate base balance. PG&E must refund to ratepayers any resulting overcollections in its 2019 Annual Gas True-up (ACT). PG&E shall update its AGT for each year of the rate case period to reflect that rate base adjustment, using the actual beginning 2019 recorded rate base balance, with all appropriate adjustments consistent with this decision.

88. Pacific Gas and Electric Company must file a Tier 1 Advice Letter, by October 1, 2019, stating the amount of its recorded 2018 capital expenditures that it intends to add to the rate base.

89. Consistent with Section 10.8.1 concerning Limited Trading Authority, Pacific Gas and Electric Company must file an annual report that notes the date of each purchase of gas by PG&E to support Baja path reliability (through any of its departments, including Wholesale Marketing & Business Development or Electric Gas Supply) from suppliers, the amount of gas purchased, the purchase price, and the sales price. The report should also include the total net cost of the program.

90. Consistent with Section 10.8.1 concerning Limited Trading Authority, if Pacific Gas and Electric Company decides to implement a new Request for Offer process, that process must be reviewed by the Commission's Energy Division through the Tier 2 Advice Letter process before PG&E selects an offer through the new process.

91. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter, within 30 days of the date that this decision is final, to modify the Balancing Charge Account consistent with the discussion in section 14.5 concerning Cost Recovery Mechanisms.

92. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter, within 30 days of the date that this decision is final, to modify the Gas Transmission and Storage memorandum account to record the under-collection of its 2019 base revenue requirement as discussed in section 14.5.5 of this decision.

93. Pacific Gas and Electric Company's (PG&E) proposal to revise the Gas Transmission and Storage Revenue Sharing Mechanism (GTSRSM) is denied in part. PG&E shall file a Tier 2 Advice change the GTSRM to remove noncore storage and change the timing for the annual transfer, as discussed in section 14.5.4 of this decision.

94. Within 30 days of the date of this decision, PG&E shall file a Tier 2 Advice Letter that provides the actual amount of cost overruns associated with pipe replacement in lieu of hydrostatic testing projects from 2015-2018.

95. Within 90 days of the date that this decision is final, the Commission's Safety and Enforcement Division (SED) shall file a compliance report with the analysis directed in section 5.6.3 of this decision. SED shall also serve the report to the service list for this proceeding.

96. Within 90 days of the date that this decision is final, PG&E must convene a workshop to identify study parameters for determining how to allocate cost for PG&E's local transmission service. We encourage non-core customers and TURN to attend. PG&E must submit to the Commission a status report after the first workshop in the following time increments: 60 days, six months, two years.

97. The Energy Division workpapers supporting the modeling used to produce the Results of Operations Tables in the appendices of this decision, in support of the adopted revenue requirement for 2019 through 2022, and workpapers not requiring a non-disclosure agreement, are received into the record of this proceeding, and identified as Late-Filed Exhibit ALJ-1. Upon the issuance of this decision, the Energy Division will provide a copy of these workpapers to Pacific Gas and Electric Company and the Commission's Public Advocates Office. Other parties to the proceeding seeking to obtain access to the workpapers shall contact Energy Division to arrange to receive a copy.

98. The Energy Division results of operations model and rates model and the workpapers supporting the modeling used to produce the rates in the appendices of this decision are received into the record of this proceeding and identified as late-filed Exhibit ALJ-2. Upon the issuance of this decision, the Energy Division will provide a copy of the results of operations, rates models,

and the workpapers supporting the model used to produce the rates to Pacific Gas and Electric Company (PG&E) and the Commission's Public Advocates Office. Other parties to the proceeding seeking to obtain access to the models and workpapers must first enter into a non-disclosure agreement with PG&E, and then contact the Energy Division to arrange to receive a copy.

99. The transcript corrections by Pacific Gas and Electric Company and The Utility Reform Network are adopted.

100. The motion of Indicated Shippers to strike portions of Pacific Gas and Electric Company's Opening Brief is denied.

101. Application 17-11-009 is closed.

This order is effective today.

Dated ____________________________, at Los Angeles, California.

# APPENDIX A - ACRONYMS

**APD:** Abnormal Peak Day
**BART:** Bay Area Rapid Transit District
**Bcf:** Billion cubic feet
**C&P:** Compression and Processing
**CAISO**: California Independent System Operator Corporation
**CGS:** Core Gas Supply
**CP:** Cathodic Protection
**CPIM:** Core Procurement Incentive Mechanism
**CTA:** Core Transport Agent
**CWD:** Cold Winter Day
**DC:** Direct Current
**DE&R:** Direct Examination and Repair
**ECDA:** External Corrosion Direct Assessment
**EG:** Electric Generation
**GRC:** General Rate Case
**GTN:** Gas Transmission Northwest, LLC
**GT&S:** Gas Transmission and Storage
**HCA:** High Consequence Area
**ICDA:** Internal Corrosion Direct Assessment
**ILI:** In-Line Inspection
**ISP:** Independent Storage Providers
**M&P:** Measurement and Control
**MMcf:** Million cubic feet
**MMcf/d:** Million cubic feet per day
**Mdth:** Thousand decatherms
**Mdth/d:** Thousand decatherms per day
**MMdth:** Million decatherms
**MMdth/d:** Million decatherms per day
**PTY:** Post Test Year
**PTYR:** Post Test Year Ratemaking
**RAMP:** Risk Assessment Mitigation Phase
**Rate Case Period:** 2019, 2020, 2021 and 2022
**SCADA:** Supervisory Control and Data Acquisition
**SED:** Safety and Enforcement Division
**S-MAP:** Safety Model Assessment Proceeding
**SMUD:** Sacramento Municipal Utility District
**TIMP:** Transmission Integrity Management Program
**TIMPBA:** Transmission Integrity Management Program Balancing Account
**UCC:** Unbundled Cost Center
**WRO:** Work Required by Others

**(END OF APPENDIX A)**

# APPENDIX B

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**(END OF APPENDIX B)**